PHD

The hierarchical control and protection of power systems

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THE HIERARCHICAL CONTROL AND PROTECTION OF POWER SYSTEMS

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Preface

This thesis is dedicated to my parents.

Preface

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SUMMARY

This thesis describes the simulation of an integrated digital hierarchical control and protection system for adaptation of the functionality of digital distance relays enabling performance optimisation under changing power system conditions.

Protection relays should ensure the prompt, reliable, selective and economic removal of the range of fault scenarios possible on the power system. For unit protection schemes, the influence of the state of the power system external to the protected unit is small and may be overcome by using bias settings. This is not so for non-unit forms of protection, essentially distance relays, where changes in the power system conditions may reduce the relay's performance considerably. The operating strategy of distance relays, by virtue of the zone settings and the characteristic shape, enables the protection to act as optimally as possible over a range of operating conditions. However, there are scenarios in which it is difficult to achieve optimal performance, the most notable being the influence of topological variations and high resistance earth faults. Here, it is beneficial to constantly change, or adapt, the functionality of the relay to ensure optimal operation. Adaptation may be achieved by a system that can monitor the state of the power system, calculate the new relay functionality based on this information and update the relay.

The integrated digital hierarchical control and protection system provides a framework

in which adaptation may be performed by exploiting advances in computer and communications technologies for the collation and dissemination of geographically distributed information. The integrated digital hierarchical control and protection system using apriori system information determines new settings and adjusts the characteristic to ensure optimum performance.

A simulation of the North Wales 400kV Supergrid Transmission Network provides the basis for a comparison of the performance of protection relays using fixed settings and characteristics against their adaptive counterparts using information derived via a hierarchical structure. The performance has been established with particular emphasis placed on the influence of variations in source capacity, topology, pre-fault loading and earth fault resistance.

The benefits and limitations of integrated digital hierarchical control and protection systems relative to alternative solutions are discussed. The practical requirements for the introduction of an integrated digital hierarchical control and protection system to the grid system within the United Kingdom are outlined.

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LIST OF SYMBOLS

A	total number of system faults.
α	proportion of line from the relaying point to the fault.
c_1	$((1 - \alpha).Z_{l1} + Z_{sn1})/ (Z_{sm1} + Z_{l1} + Z_{sn1})$.
c_0	$((1 - \alpha).Z_{l0} + Z_{sn0})/ (Z_{sm0} + Z_{l0} + Z_{sn0})$.
C	current cost.
D_p	dependability Index.
E_{m1}	positive phase sequence voltage of source M.
E_{n1}	positive phase sequence voltage of source N.
F	future cost of finance.
F_1	number of faults where there was a failure to trip the circuit breaker.
F_2	number of system faults on which there was unwanted system operation.
h	ratio of sending end generator terminal voltage to receiving end generator terminal voltage (E_m / E_n).
i	rate (eg: interest rate or rate of increase in cost of operation and maintenance).
I_{13}	the fault current flowing in feeder Z_{13} from busbar 1 to busbar 3.
I_{14}	the fault current flowing in feeder Z_{14} from busbar 1 to busbar 4.
I_{34}	the fault current flowing in feeder Z_{34} from busbar 3 to busbar 4.
I_3	the fault current from the generator at busbar 3.
I_{42}	the fault current flowing in feeder Z_{24} from busbar 4 to busbar 2.

I_a, I_b, I_c	a-phase, b-phase, c-phase line currents.
I_{A0}	zero phase sequence current flowing in feeder A between busbars A and B.
I_{A1}	positive phase sequence current flowing in feeder A between busbars A and B.
I_{A2}	negative phase sequence current flowing in feeder A between busbars A and B.
I_{C0}	zero phase sequence current flowing in feeder C between busbars A and B.
I_{C1}	positive phase sequence current flowing in feeder C between busbars A and B.
I_{C2}	negative phase sequence current flowing in feeder C between busbars A and B.
I_{AT}	the fault current flowing in feeder Z_{AT} from busbar A to busbar T.
I_{CT}	the fault current flowing in feeder Z_{BT} from busbar C to busbar T.
I_f	fault current ($= I_{f1} + I_{f2} + I_{f3}$).
I_{f0}	zero phase sequence fault current.
I_{f1}	positive phase sequence fault current.
I_{f2}	negative phase sequence fault current.
I_{LD1}	pre-fault positive phase sequence a-phase load current.
$I_{measured}$	measured current at relaying point.
I_{mf}	fault current flowing from busbar M to the fault point F.

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I_{nf}	fault current flowing from busbar N to the fault point F.
I_{res}	$I_a + I_b + I_c$.
K_{res}	$(Z_{10} - Z_{11})/3.Z_{11}$.
n	number of years.
P	amount borrowed (present worth).
R	annual capital recovery cost.
R_f	fault resistance.
S_p	security index.
θ	argument of the earth fault impedance factor, Z_{rf} or the difference in angle between two busbar voltages.
T	throttling or infeed ratio.
U_{fl}	pre-fault voltage at the fault point.
V_a, V_b, V_c	a-phase, b-phase, c-phase line voltages.
$V_{measured}$	measured voltage at relaying point.
[Y]	admittance matrix.
$[Y_{REDUCED}]$	reduced admittance matrix equivalent to [Y].
Y_A	sub-matrix of [Y].
Y_B	sub-matrix of [Y].
Y_C	sub-matrix of [Y].
Y_D	sub-matrix of [Y].
Y_{km}	elements of admittance matrix, [Y], where k and m are integers representing the rows and columns of the matrix respectively.

	Equivalent to admittance between k and m (= G_{km} + B_{km}).
[Z]	impedance matrix.
Z_{km}	elements of impedance matrix, [Z], where k and m are integers representing the rows and columns of the matrix respectively.
Z_{13}	impedance of transmission line from busbar 1 to busbar 3.
Z_{14}	impedance of transmission line from busbar 1 to busbar 4.
Z_{24}	impedance of transmission line from busbar 2 to busbar 4.
Z_{34}	impedance of transmission line from busbar 3 to busbar 4.
Z_{AT}	impedance of the transmission line from busbar A to the throttling point T.
Z_{BT}	impedance of the transmission line from busbar B to the throttling point T.
Z_l	line impedance.
Z_{l1}	positive phase sequence line impedance.
Z_{l0}	zero phase sequence line impedance.
$Z_{measured}$	measured impedance by a distance relay.
Z_{rf}	earth fault impedance factor.
Z_{m0}	zero phase sequence mutual impedance between the faulted and unfaulted transmission line.
Z_{sm1}	positive phase sequence impedance of source M.
Z_{sm0}	zero phase sequence impedance of source M.
Z_{sn1}	positive phase sequence impedance of source N.

Z_{sn0} zero phase sequence impedance of source N.

Z_{t1} positive phase sequence impedance of transformer.

$Z_{zone\ 1}$ zone 1 setting of distance relay.

$Z_{zone\ 2}$ zone 2 setting of distance relay.

$Z_{zone\ 3}$ zone 3 setting of distance relay.

LIST OF ABBREVIATIONS

ACC	Area Control Centre
AI	Artificial Intelligence
AVR	Automatic Voltage Regulator
CB	Circuit Breaker
CCT	Critical Clearing Time
CNU	Communications Network Unit
CT	Current Transformer
DAU	Data Acquisition Unit
DCU	Data Communications Unit
EBU	Emergency Back Up
EHV	Extra High Voltage
EMI	Electromagnetic Interference.
EMS	Energy Management System
EPRI	Electric Power Research Institute
FGT	Full Graphics Terminal
HV	High Voltage
IEE	Institution of Electrical Engineers
IEEE	Institution of Electronic and Electrical Engineers
ISDN	Integrated Services Digital Network
ISO	International Standards Organsiation

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LAN	Local Area Network
LV	Low Voltage
METRO	Micro Enhanced Telecommand Remote Outstation
NCC	National Control Centre
NGC	National Grid Company
OSI	Open Systems Interconnection
PDS	Program Development System
REF	Restricted Earth Fault
RTU	Remote Terminal Unit.
SCADA	Supervisory Control and Data Acquisistion
TIE	Telecontrol Interface Equipment
VT	Voltage Transformer

CHAPTER 1

INTRODUCTION

1.1 Introduction

1.1.1 Motivation and Objectives of Research

Power system operators are increasingly required to respond to changes in a fast, efficient, flexible and economic manner whilst maintaining the integrity of the complex systems they operate. Nowhere is this more relevant than in the United Kingdom following the privatisation of the electricity supply industry in 1991. Within this framework electrical utilities are asking themselves a number of pertinent questions.

- How can the services that the power utility provide, both internally and externally, be improved and the operation of the network be optimised ?
- How can the resources of the power utility be utilised to their best advantage ?
- How can all the different aspects of the power utility business be assessed in order that fast, correct decisions can be made ?
- How can the power utility respond to change ?
- How can potential problems be identified and corrected ?

Against this background, new technologies, especially in computing (microprocessors) and digital communications, are developing rapidly. A wide range of microprocessor-based devices are now commercially available for power system monitoring, control and relaying. Microprocessor technology solutions have attractive benefits over alternative methodologies including reduced power requirements, reduced space requirements, sophisticated signal analysis, self-monitoring ability, flexibility, enhanced operator interfaces and comprehensive data storage and retrieval ability.

In parallel with the evolution of the microprocessor, there have been significant advances in digital communications technology. Fibre optic communications links have been developed that are immune to electro-magnetic interference (EMI), avoid the need for electronic signal repeaters and complex switching arrangements, and have a high bandwidth and low attenuation. The requirements for reliable and high performance communications channels for data transfer and control in power systems, especially under faulted network conditions, give fibre optic communications links significant potential.

New tools and concepts that exploit the greater flexibility and efficiency provided by microprocessor and communications technology have also emerged. Early microprocessor-based devices had largely been produced to perform a single or related range of tasks without the assistance of other devices. Whilst these devices were stand-alone and acted autonomously within a business or process, the realisation that the information used or generated at one stage may be useful at another, for say performance enhancement, became apparent. This resulted in the interconnection of autonomous computers via communications media and became known as the computer network. A number of topological variations for the configuration of computer networks have emerged, one of which is hierarchical and forms the basis for the integrated digital hierarchical control and protection system. There have also been considerable developments in the rules and conventions by which computers access the network and communicate with one another.

The computer network is increasingly being used for factory and office automation, providing a framework for the collation and dissemination of information. The widespread availability of up-to-date information on any requested aspect of the operation or process enables:

- Provision of a better service to customers that is in line with changing market requirements.
- Optimised performance achieved via planning, forecasting and quality assessment tools.
- Improved access to strategic information and quality of supply.
- Maximum utilisation of available resources.
- Improved efficiency resulting in reduced cost.
- Increased reliability of supply.
- Marked increases in levels of automation.

The computer software plays an important and integral part to the hardware. Developments in Computer Aided Software Engineering tools, database techniques, artificial intelligence and graphical user interfaces provide the user with considerable power in a user friendly environment.

This technology can provide answers to the questions posed at the beginning of the section and has the potential for revolutionising power system control and protection. However, there are a number of questions that the application of this technology to power systems, as opposed to other processes, need addressing. These questions include not only the technical aspects but also the wider economic issues. In particular, there is a great deal of concern regarding the reliability, security and costs of implementation. To answer these questions, research has been undertaken at the University of Bath, the objectives of which are two-fold:

- To simulate an integrated digital hierarchical control and protection system.
- To evaluate the potential benefits and limitations of introducing such a system to the United Kingdom's North Wales 400 / 275 kV network.

1.1.2 History

Digital computers have been applied to the power industry since their introduction. They have been used for analysis, monitoring, control and protection of the power system. Initial research concentrated on the development of mathematical models for the numerical representation of power systems on the computer. Off-line analysis techniques for load flow analysis [1.1, 1.2], transient [1.3, 1.4] and dynamic [1.5, 1.6] stability analysis, and security assessment [1.7, 1.8] were developed. These calculations were performed on mainframe computers or mini-computers, consuming large amounts of power and requiring big, air-conditioned storage space. Towards the end of the 1960s and during the early 1970s microprocessor-based systems, supported by digital communication systems, emerged. The availability of reliable, small, cheap microprocessors was to pave the way for considerable developments in power system monitoring, control and protection [1.9, 1.10].

The application of digital techniques for the protection of power systems was first proposed by Rockefeller [1.11] in 1969. The feasibility and concepts of protecting equipment within a substation using a single computer, together with requirements and problems, were outlined. With the exception of this work, initial research concentrated on the replacement of conventional stand-alone protection relays with digital equivalents having similar, if not better, functionality. Mann and Morrison [1.12, 1.13] developed a digital computer-based distance-type protection suitable for protection of transmission lines. Using a sample and derivative technique it was possible to estimate the current and voltage phasors from sampled data and determine the impedance. This work was extended by the Westinghouse Electric Corporation and the Pacific Gas and Electric

Company [1.14, 1.15] and after field trials resulted in the first practical application.

Hope and Umamaheswaran [1.16] recognised the importance of analysis of the sampled data in the frequency domain and developed a number of techniques for impedance measurement using orthogonal filters. As digital signal processing techniques were developed in conjunction with the reduced cost of hardware a multitude of papers started to emerge [1.17, 1.18, 1.19].

Digital techniques have also been applied to load shedding and load restoration functions. These require the measurement of power system frequency and rate of change of frequency. Methods were based on the zero-crossing instant of the voltage waveform [1.20], Fourier Transform Analysis [1.21, 1.22] and filtering techniques [1.23, 1.24]. Whilst these techniques remain the basis for the determination of power system frequency, the inherent errors of each methodology have been reduced by the incorporation of filtering methodologies [1.25, 1.26].

Digital techniques for generator [1.27, 1.28], transformer [1.29], transmission line [1.30] and multi-terminal transmission line [1.31, 1.32, 1.33] differential schemes have emerged. These schemes have the added complexity that measuring parameters are derived from two or more different points on the power system, that may have completely different geographical locations requiring more than one microprocessor unit and a communications link across which signals must be correlated.

The requirements for information exchange between computers added a new dimension to electrical communications culminating in developments in digital communications and the computer network [1.34, 1.35]. In the 1980s, the combination of computer and digital communications technology was applied to the electric utility market and saw the emergence of control centres with Supervisory Control And Data Acquisition (SCADA) systems [1.9]. In their simplest form, SCADA systems enabled the gathering of data, the displaying of information and the control of selected elements. The SCADA system comprised a master computer and a number of remote terminal units (RTUs). The master computer could interrogate the RTUs, via a communications link, enabling the provision of on-line data gathering. This information enabled the power system operator to have a better understanding of the current status of the system and using this information, if necessary, issue control actions to plant, via the SCADA system, including:

- Open / close circuit breaker.
- Change tap setting of transformer (up / down).
- Reset relays.
- Change automatic voltage regulators (AVRs) operation (manual / automatic).

More recently, the functionality of SCADA systems have been enhanced to include Automatic Generation Control, Energy Management System (EMS), Distribution Management Systems, Load Management System, Automatic Meter Reading and

Automatic Mapping / Facilities Management Systems.

In addition to the use of digital computers and communications links for power system control, applications have been developed for protection. Digital tele-protection systems [1.36] enabled communications links between relays providing signal conditioning, data encoding / decoding and error detection. These enable the reliable, real-time transfer of information, such as the Direct Transfer Trip in protection signalling.

Until the 1970s monitoring, control and protection functions had been kept independent. In the conventional substation there were high levels of wiring to the control room, and duplication of instrumentation and measurement transducers. However, computers now had the ability to easily communicate with one another. This technology made the integration of monitoring, control and protection information possible, with the incentive to overcome limitations of the conventional substation. In the United States of America, the Houston Lighting and Power Company, in conjunction with the Electric Power Institute of Texas A & M University, developed and installed an integrated control, monitoring and protection system known as the Feeder Protection and Monitoring System [1.37, 1.38]. The system provided integrated feeder monitoring, fault data acquisistion, arcing fault detection and protection. The utilities experience based on field tests and subsequent use of the system highlighted the benefits gained by the availability of additional information and improved performance [1.39].

Westinghouse ABB T&D, sponsored by Electric Power Research Institute (EPRI), expanded on this by developing a totally integrated substation. They demonstrated the feasibility of introducing an integrated digital system for the protection, control and monitoring within a substation [1.40, 1.41, 1.42] by developing a system known as WESPAC. The system provided transmission line, bus and transformer protection relaying together with benefits gained by using integrated systems. The integrated environment enabled optimisation of the performance of the protection and control functions and provided additional support functions, using locally available information, within the substation.

In Japan, Takak et-al [1.43] initially exploited the technology by developing an intra-station optical fibre data transmission system for power system control and protection. More recently, Suzuki, Matsuda, Ohashi, and Sano [1.44] developed a substation digital protection and control system using a fibre optic local area network (LAN). Field tests were undertaken in an Extra High Voltage (EHV) substation over the period of a year and highlighted the immunity of such systems to EMI.

Concurrently with the developments in digital computer and communications technology there have been developments in the concepts of monitoring, control and protection of power systems. These have evolved as increasing knowledge of the performance requirements of power systems have emerged by improved analytical techniques and the availability of actual power system performance data. The need to avoid protection relay mal-operation and ensure continuing optimal relay operation, has led to the concept of adaptive protection relaying which has been defined by Horowitz et-al [1.45]:

> "Adaptive protection is a protection philosophy which permits and seeks to make adjustments to various protection functions in order to make the system more attuned to power system conditions"

Adaptive protection enables the relay to have a superior performance to existing conventional protection relays. Horowitz et-al [1.45] described the potential benefits and principles of adaptive techniques for transmission systems. The application of adaptive techniques to reliability, multi-terminal transmission line protection, transformer protection, relay setting and automatic reclosing were described. The superior performance of the adaptive protection relays was achieved by supplying the devices with additional information. Two schools of thought as to how this information was to be derived emerged.

The first school of thought followed a more conventional approach. Moore [1.46] developed a discrete stand-alone adaptive distance relay provided with the traditional input measurands of its conventional equivalent counterpart. By more detailed analysis of the existing information in the form of the traditional current and voltage input measurands at the relaying point, using enhanced signal processing techniques and adaptive filter theory, improved earth fault coverage and resistance to power swings was achieved. More recently Wiszniewski and Kasztenny [1.47] developed an adaptive transformer differential relay with improved reliability in which the decision to operate was formulated using fuzzy set theory. Fitton et-al [1.48], using a neural network approach, developed an auto-reclose relay that optimised the time to reclosure by adapting to the time for extinction of the secondary arc within the circuit breaker. The use, by these systems, of only the traditional input measurements has both benefits and limitations. One of the more marked limitations is that they used only the limited information available at the relaying point. This limits the performance enhancements possible.

The second school of thought, addressing this limitation, supplied the relay with additional information relating to the current status of the entire power system. Rockefeller et-al [1.49] described how a simple impedance model of the power system, with up-to-date parameters relating to the current power system conditions was capable of improving protection reliability and maximising utilisation of the transmission system. Using this approach, Xia et-al [1.50] proposed a distance relay that adapted its characteristic to optimise its performance under the influence of high resistance earth faults. In its simplest form, the additional information was derived from a central computer monitoring the status of the system and providing the relays with updated impedance model parameters. Phadke [1.10] described a computer integrated approach, similar to the WESPAC system, more applicable to the large power systems of today.

The speed of operation, inherent self-monitoring capability and ability to form part of integrated monitoring, control and protection systems now make digital relays an attractive alternative to their analogue and electro-mechanical equivalents. With the integrity of the power system closely correlated with the performance of the protection system coupled with the need for flexible, economic, reliable, highly utilised and easily managed systems, there is an incentive to consider the potential benefits that the additional functionality available through the introduction of integrated systems can give. The application of digital technology is increasingly being used in new substations. However, nowhere has integration of the protection system distributed over a wide geographical area taken place and it is this area that the research seeks to address.

1.2 Structure of Thesis

A brief description of the structure of the thesis is outlined.

By way of introduction, Chapter 2 describes the transmission system of the United Kingdom by considering the three main sub-systems of which it is made: the power plant, the control system and the protection system. The principles behind each of the sub-systems and the current technology employed are outlined. This provides an understanding of the current transmission system to enable an appreciation of the issues involved in moving from the existing system to the integrated digital hierarchical control and protection system.

Chapter 3 outlines the concepts associated with computer integrated system. The alternative computer network architectures, together with the benefits and limitations of each network, are reviewed. It is shown that a computer integrated system with the computing resources arranged hierarchically provides the environment for the collation and dissemination of information in large, complex systems such as those of power systems for performing integrated control and protection. The application of the computer integrated system to power systems in the form an integrated digital hierarchical control and protection system is introduced.

Chapter 4 outlines the necessity for the introduction of integrated digital hierarchical control and protection systems. The limitations of conventional protection systems are outlined. This highlights the need for optimisation of the relay functionality under the influence of changing power system operating conditions and leads to the concept of adaptive protection.

Two principle methods of relay adaptation are available: setting adaptation and characteristic adaptation. Chapter 5 describes the principles and use of the hierarchical control and protection system for the adaptation of the protection relay setting. The settings are performed using a reduced impedance model, located in the substation, whose parameters are continually updated to reflect the current power system conditions. A number of strategies for the adaptive setting of protection relays, including a novel method which sets the relay by analysing the performance of a setting in terms of dependability and security, are presented. Results of the performance of a number the adaptive settings relative to the performance of the actual settings for relays within the North Wales 400 / 275 kV network are presented. The chapter is concluded by outlining the limitations in the adaptive setting of distance relays.

Chapter 6 describes the principles and use of the hierarchical control and protection system for adapting the characteristic of distance relays, again using a reduced impedance model with up-to-date parameters. The influence of power system parameters on the measured impedance by distance relays subjected to a-phase to earth faults with varying fault resistance is presented. It is shown that characteristic adaptation enables substantial improvements in performance relative to conventional distance relay characteristics.

Chapter 7 discusses the computer simulations developed to illustrate the benefits and limitations of the integrated digital hierarchical control and protection system relative to conventional systems. Two applications, that operate in a Microsoft Windows 3.1 environment, are described. The first application simulates a hierarchical control and protection system for the adaptive setting of distance relays and enables comparison of the performance of adaptively set relays, subject to the various setting algorithms, and conventional stand-alone relays. The second simulation enables comparison of the performance of the residually compensated a-phase to earth element of a relay with an adaptive characteristic and conventional relay characteristics (mho, quadrilateral and lenticular).

Chapter 8 outlines the benefits and limitations of the integrated digital hierarchical control and protection system relative to alternative solutions. Initially qualitative arguments are used to illustrate the benefits and limitations of the integrated digital hierarchical control and protection system. These are then quantified simplistically in economic terms and it is shown that, in the long term, investment in the integrated digital hierarchical control and protection system, as opposed to other alternatives, is beneficial.

The practical requirements for the introduction of an integrated digital hierarchical control and protection system to the grid system within the United Kingdom are outlined in Chapter 9. Initially, the steps necessary in the introduction of the system, including feasibility study, requirements analysis, design and implementation, are outlined. Using the existing system as a basis, an evolutionary approach to the realisation of the integrated digital hierarchical control and protection system is described. The chapter concludes by highlighting further developments in technology required, and some of the social issues necessary for consideration, in the introduction of the integrated digital hierarchical control and protection system.

Chapter 10 concludes the report and outlines proposals for future work.

It should be noted that all figures and tables associated with a chapter are presented at the end of the respective chapter. The references in each chapter are detailed in Chapter 11. Detailed reasoning and theory are presented in appendices towards the end of the thesis.

CHAPTER 2

BACKGROUND

2.1 Introduction

The electricity supply system of the United Kingdom is one of the largest and most highly integrated in the world. The electricity supply system, in its most abstract form, may conveniently be divided into three main subsystems: generation, transmission and distribution [2.1]. Generating stations are located in areas of high amenity which may have geographical positions that differ from load centres. The transmission network interconnects generating plant and enables the bulk transfer of electricity to load centres. The distribution system supplies this energy to the individual consumer. Each of the three subsystems (ie: generation, transmission and distribution) may further be decomposed, Fig.2.1, into the power subsystem responsible for the physical transfer of electricity, the control subsystem responsible for controlling the transfer of electricity and the protection system responsible for protecting the system.

To provide a framework upon which to discuss the research, this chapter outlines the means and principles used for the supply of electricity, and the control and protection of the power system of today. Whilst the generation, transmission and distribution systems each play an important and integral role in the supply of electricity, this research has concentrated on the transmission system and the discussion will be restricted to this.

2.2 Power Plant in the UK Grid System

The transmission system of the United Kingdom performs two main functions: interconnection to allow the pooling of generation on a national basis, and the bulk transfer of electricity from generating stations to load centres [2.2]. This enables economic power generation, security of supply, reduction in spinning reserve, reduction in margin, and resource availability and demand. To facilitate the economic and reliable supply of electricity to the customer [2.3], a system that has become known as the grid is used. The concept of the grid system is simplistically illustrated in Fig.2.2.a. Transmission lines are joined together at substations or nodes. Each node is capable of having generating plant and / or load connected to it. In addition, transmission lines may be switched in and out of service. Nodes where loads and generating plant are not connected are known as marshalling points. Should there be loss of a line, Fig.2.2.b, due to a fault or maintenance projects, supply may be maintained via alternative routes thus improving the system security. Power transmission on the grid system is conducted at 400 kV and 275 kV, the dimensions of power plant on the system being tabulated in Table 2.1. The operation of the power plant on the system is controlled by a comprehensive system that forms the subject of the following section. Faulted plant is removed from service by protection devices which are discussed in section 2.4.

2.3 Power System Control in the UK Grid System

2.3.1 Introduction

Control of the National Grid Company (NGC) power system is achieved by an EMS that came on-line in May 1994. Control of the power system, and of generators of despatchable size, is effected through the National Control Centre (NCC) at Wokingham and four Area Control Centres (ACCs) at Bristol, Birminham, Coventry and Leeds, Fig.2.3 [2.5]. A standby NCC is located in St. Albans, London that is also used for Dispatcher Training. This arrangement is hierarchical with NCC responsible for overall control of the NGC system and for the co-ordination of the ACCs. The ACCs provide, and are responsible for, detailed control within their respective regions.

2.3.2 Control Centre Computers

At each control centre, a fully dual redundant computer system is installed providing on-line SCADA, animated wall diagrams, graphical visual display units, data storage and power system analysis applications. The system, Fig.2.4, comprising three Cyber 180-960 computers, are arranged as a redundant pair (Main 1 and Main 2) and an Emergency Back Up (EBU) system. A fourth Cyber 180-830 computer is provided for software development, known as the Program Development System (PDS). In the normal mode of operation, both Main 1 and Main 2 provide EMS services. Should Main 1 be lost, the system automatically changes to Main 2 and vice-versa. Both Main 1 and Main 2 are capable of providing all services on their own. Should both Main 1 and Main 2 fail, the EBU system is brought on-line manuallly.

The standby NCC at St. Albans, London has a Cyber 180-960. This is a full replicated system to the one provided at Wokingham. For operation, the computer must be loaded with the required software and database. Initialisation of the system automatically re-routes communications from Wokingham to St. Albans.

The individual Cyber computers are interfaced by duplicate Ethernet channels. A mass data storage disk, with twin magnetic tapes, is provided for back-up and historical data storage purposes. Communications between control centres is achieved via the Communications Network Units (CNUs), a microprocessor-based bus interfacing device. In a similar manner, the interface of power system operators to the system is undertaken via the Full Graphics Terminal (FGT); and the data aquisition from outstations at the control centre is undertaken by the Data Communication Units (DCUs). The CNU also provides the mechanism for interfacing to external devices, such as the wall diagrams, via Telecontrol Interface Equipment (TIE).

2.3.3 Outstations

The control centres monitor and control the power system via dual-ported Micro

Enhanced Telecommand Remote Outstations (METROs). The METROs have analog and digital capability with input quantities from 0 to 10 mA. In monitoring the system, received data is scaled and time-tagged, althought the latter is not transmitted to the control centre. Comprehensive inter-locking between the control centre and the METRO provides reliable plant control.

2.3.4 Communications

A pyramidal communications network, Fig.2.5, has been implemented between the NCC and ACCs for power system monitoring and control. This communications system provides duplicate, separately routed channels between the NCC and the ACCs. This enables the NCC to communicate either directly with each of the ACCs or via an alternative ACC and a tie line. Data is exchanged between the control centres (either NCC to ACC or ACC to ACC) using CDCNET, a communications system provided by Control Data Corporation. CDCNET is a wide band communications systems based on the Open Systems Interconnection (OSI) reference model. It carries the EMS Application Data Link (EMS Link) providing bi-directional communications between the control centres for SCADA, application program and other data transfer. CDCNET uses the NGC Corporate Communications Network, which links all major operational and corporate centres using Public Data Network Megastream links.

The control centres, via the DCUs, provide data paths to the METROs for acquistion of measured analogue and digital power system status information. To ensure reliable communications duplicate, separately routed channels are used and connected to both the Main and EBU computers, Fig.2.6. The costs of redundancy are reduced by using a triangulated approach, Fig.2.7. In a similar manner to the pyramidal communications network between control centres, this provides duplicate channels to each outstation, one of which is direct, and the other via an alternative outstation in the same geographical region and tie line. Communications between the control centres and the outstations uses the GI74 protocol at 300 bd. This protocol allows regular transmission of analogue measurements, which are scanned about once a second. Digital status changes interrupt the analogue scanning on occurence for transmission of this information.

2.3.5 EMS Functionality and Tools

The EMS incorporates comprehensive tools for the monitoring, analysis and control of the power system. These tools include data configuration, display and power system analysis, all of which enable the operator to more optimally control the power system.

The power system operator can request the on-line transfer of any parameter within the system. All analogue data can be checked for limit violations. Historic data for 10 days of power system operation is available on disc and comprehensive retrospective and on-line data analysis facilities are provided. The system has comprehensive event handling and disturbance data collection functions.

A wall diagram provides an overview of the system showing, circuit status, substation splits, reference time, frequency and inter-area flows. Alarm and telephone annunciation are also displayed. Colour graphics terminals provide high resolution display of the power system configuration, with each console having the ability to support 4 terminals. Databases may be ammended and control may be exercised from each terminal, the level of access being controlled by a master console which assigns individual terminals or groups of terminals to have the required functionality. The terminals have the capability of viewing the status of the power system at different levels of abstraction. In the most abstract form a whole national overview of the system can be obtained. Alternatively sections of the system or detailed configurations of substations can be displayed.

Power system analysis applications can be performed concurrently with the on-line monitoring and control of the system. Tools include topology checking, analogue state estimation, security analysis, load flow analysis and optimal power flow solutions.

2.4 Power System Protection in the UK Grid System

2.4.1 Introduction

Power plant is protected by protection relays. To ensure high fault detection reliability, protection equipment is arranged such that any system fault is detected by at least two independent protective devices known as first main and second main protection, Fig.2.8.

To minimise the risk of common-cause failures as much diversity should be introduced as possible. This should include, but not be limited to the use of different protection principles, different signalling equipment and media, differently routed communications channels, and different equipment manufacturers. In addition, maximum diversity should be extended to the protection systems for parallel circuits. The protection philosophies for the different types of plant within the transmission system are briefly discussed. A knowledge of the types of protection available, and there concepts, is assumed.

2.4.2 Protection Equipment for Transmission Feeders [2.6]

The type of protection used for the protection of transmission feeders is governed by the circuit length and its configuration. For plain feeders, the first main protection is of unit type and the second main protection is normally a three / four zone distance relay. In some applications it is not possible to use unit schemes to perform the first main protection task. Here, distance protection is used. For cases where two distance protections are used, one should be of the blocked type and the other of the accelerated trip type if possible.

For transformer feeders, as with plain feeders, first and second main protection are required at both ends of the feeder. The first main protection is provided by some form of unit protection or distance protection and the second main protection by a distance scheme. In some applications, there is insufficient fault current at the transformer end to initiate the protection. This is overcome by employing unit schemes on the transformer and either a unit or distance scheme on the line.

For teed feeder applications, if there is access to the tee-point for installation of current transformers (CTs) and / or voltage transformers (VTs), then each leg of the circuit is protected as a plain feeder and a circulating current zone using differential schemes is established at the tee-point. An intertripping arrangement is required to ensure clearance of faults initiated by protection located at the tee-point. By paralleling current transformers at the tee-point, the cost of one set of CTs can be saved at the expense of reduced accuracy in the protection. For applications where the tee-point is not accessable to measurement transducers, a unit protection scheme provides the first main protection and a distance scheme providing second main protection are employed.

2.4.3 Protection Equipment for Transformers [2.7, 2.8, 2.9]

For two winding transformers, a differential protection scheme is normally used for the first main protection. Restricted earth fault (REF) protection provides the second main protection. Auto-transformers are protected by a circulating current differential protection scheme providing the first main protection and overcurrent protection providing the alternative second main protection. Both two winding transformers and auto-transformers have winding temperature protection and Buckoltz protection. These incorporate alarm and trip facilities.

2.4.4 Protection Equipment for Busbars [2.10]

Busbars are not inherently protected in the power system, and as such require their own protection schemes. The first main protection is provided by a frame earth or differential protection scheme. Backup protection is provided by remote distance protection.

2.4.5 Protection Equipment for Circuit Breaker Failure [2.11]

Circuit breakers may fail to trip when instructed to do so. Circuit breaker failure is detected by a current check relay which continuously monitors the circuit load, but whose output contacts are only permitted to operate following the operation of the circuit trip relays. On operation of the current check relay contacts, a time delay is initiated which on expiration will initiate the tripping of remote circuit breakers to clear the fault (first main protection). In a similar manner to busbar protection, the back-up protection function is performed by remote distance protection.

2.4.6 Protection Equipment for Series Reactors and Shunt Compensation Plant [2.7]

Series reactors are protected by their own circulating current differential protection scheme or included within the protection zone of other protection (first main protection). For applications where the reactor is connected directly to the busbar, it must be included in the station busbar protection zone. Overcurrent protection, located on each side of the reactor, provides back-up (second main protection) protection. Shunt compensation reactors must always be protected by their own circulating current differential protection scheme providing the first main protection. Overcurrent protection, with a residually compensated centre element, provides back-up protection for shunt compensation reactors (second main protection). Operation of protection must ensure intertripping of all circuit breakers capable of providing fault infeeds to either the series or shunt compensated reactor. Both series and shunt reactors have winding temperature protection and Buckoltz protection.

2.4.7 Protection Equipment for Quadrature Boosters [2.7]

Quadrature boosters are protected by a circulating current differential protection scheme having three sets of current transfomers located on the incoming connections, outgoing connections and the neutral end of the HV winding of the shunt regulating transformer (first main protection). Overcurrent relays provide back-up protection (second main protection). Winding temperature and Buckoltz protection is provided.

Table 2.1: Dimensions of the UK Transmission System [2.4]	
400 kV transmission lines	8417 circuit kilometers
275 kV transmission lines	4386 circuit kilometers
Number of Transformers	531
Number of Substations	194

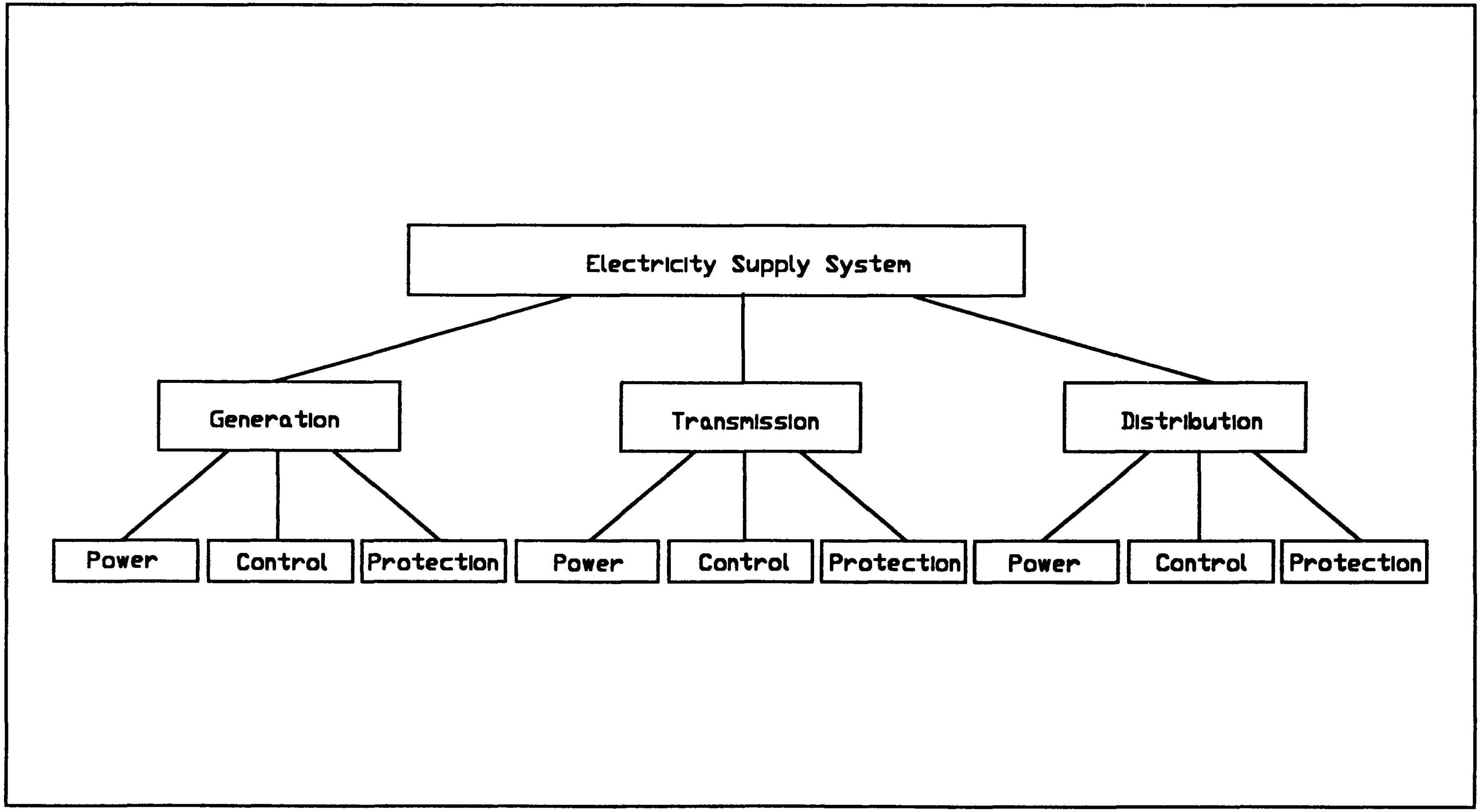

Figure 2.1 Abstract Representation of the United Kingdom Power System

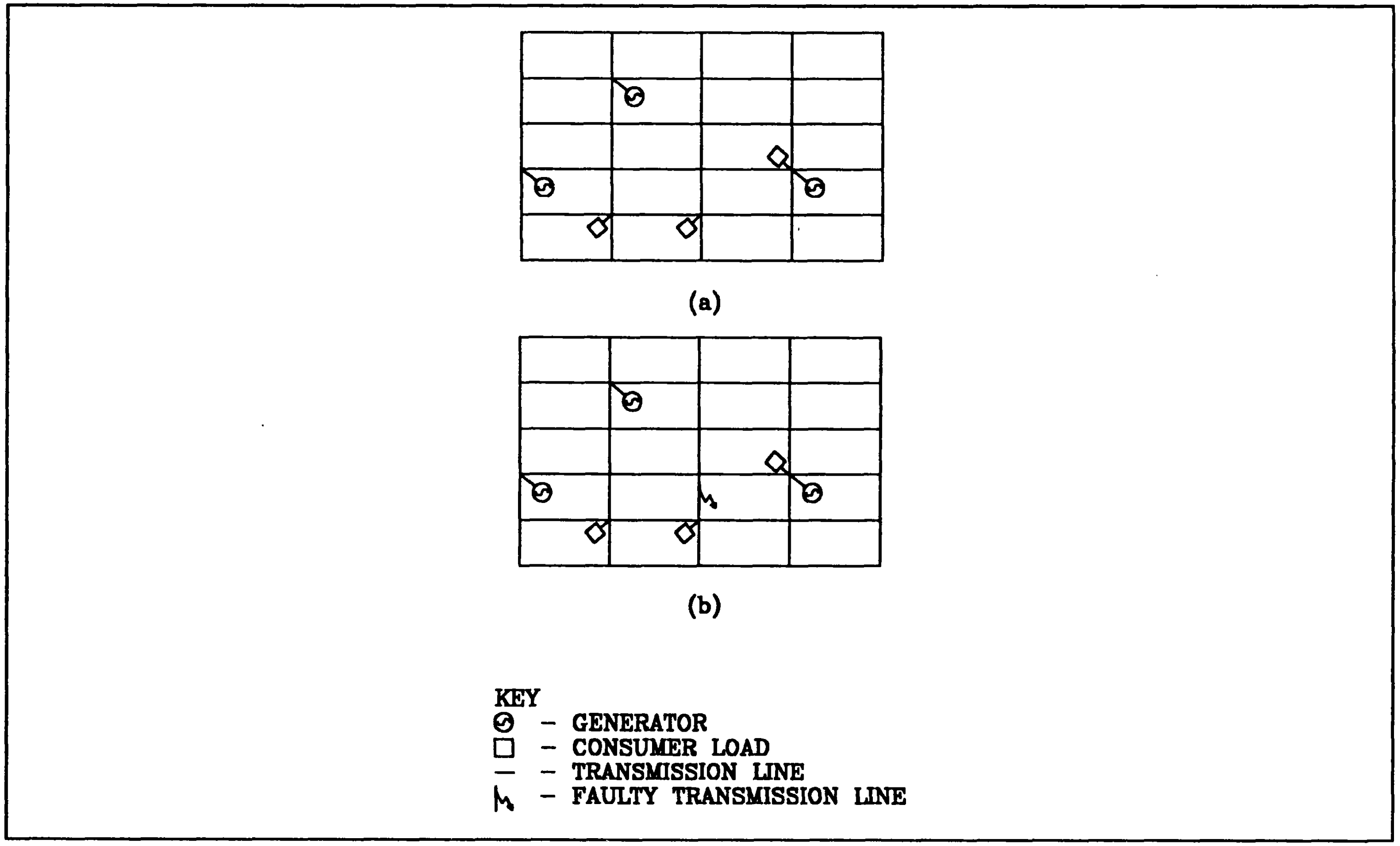

Figure 2.2 Principle of the Grid System

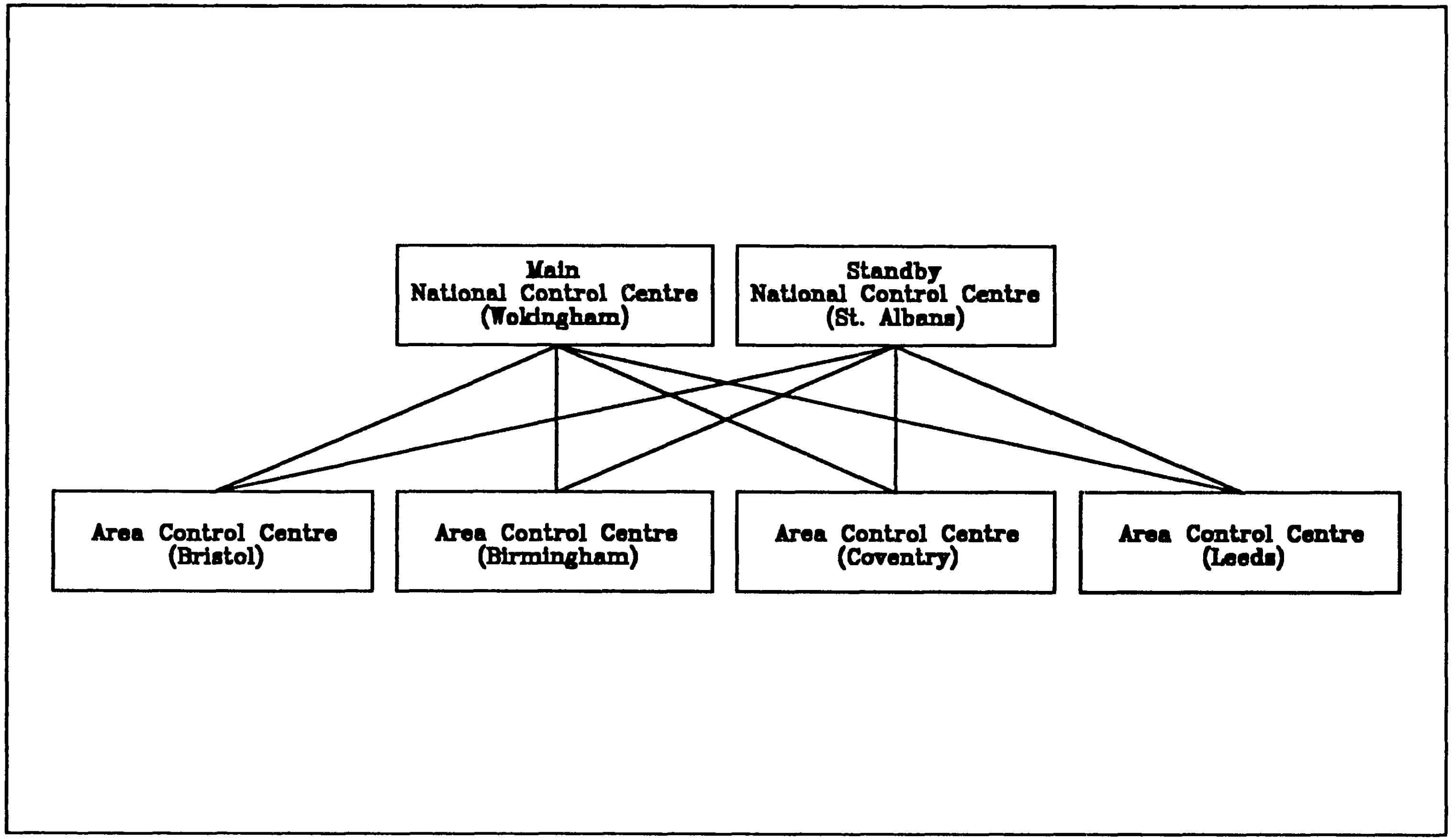

Figure 2.3 Overview of Power System Control on the Power System of England and Wales

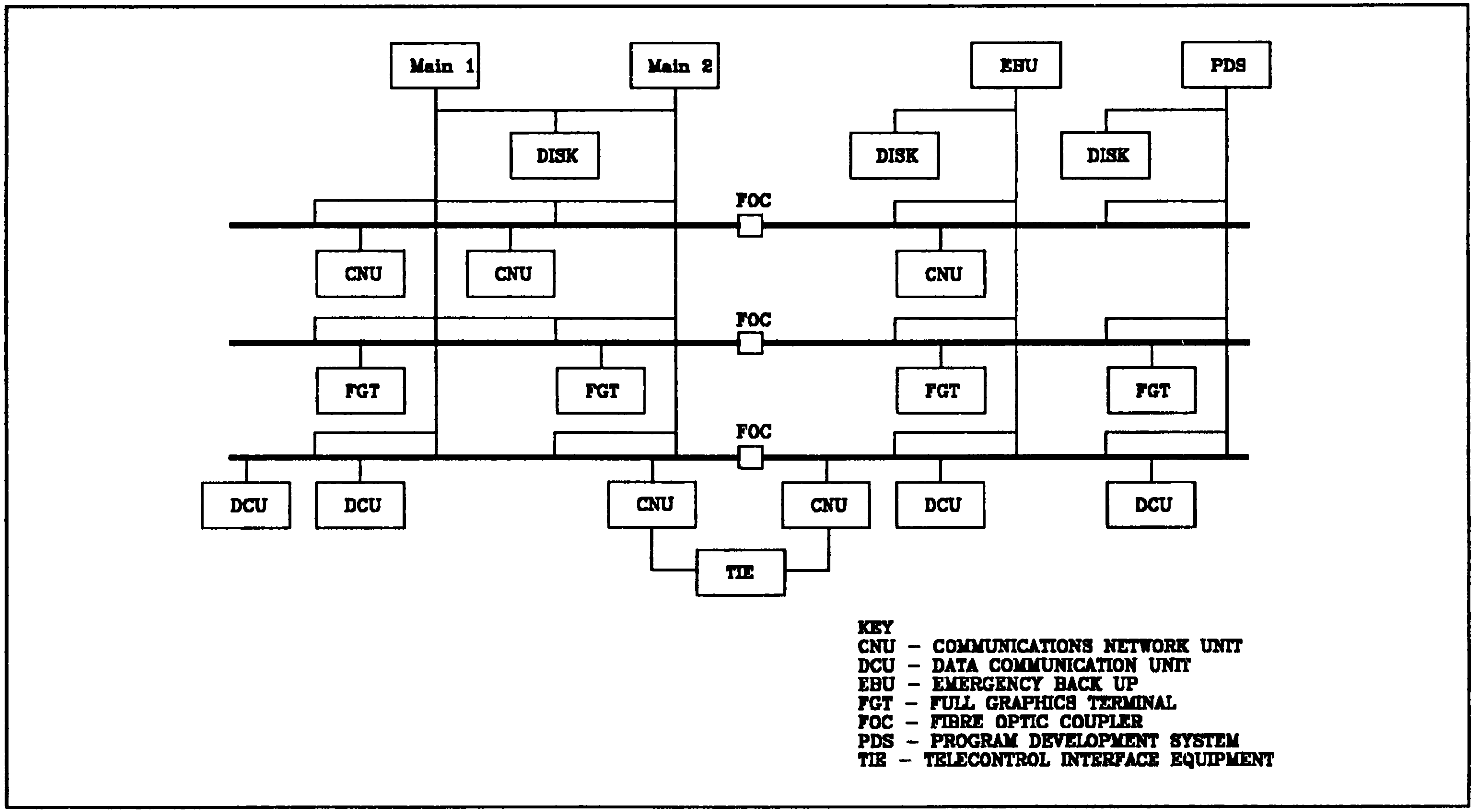

Figure 2.4 EMS Computer System

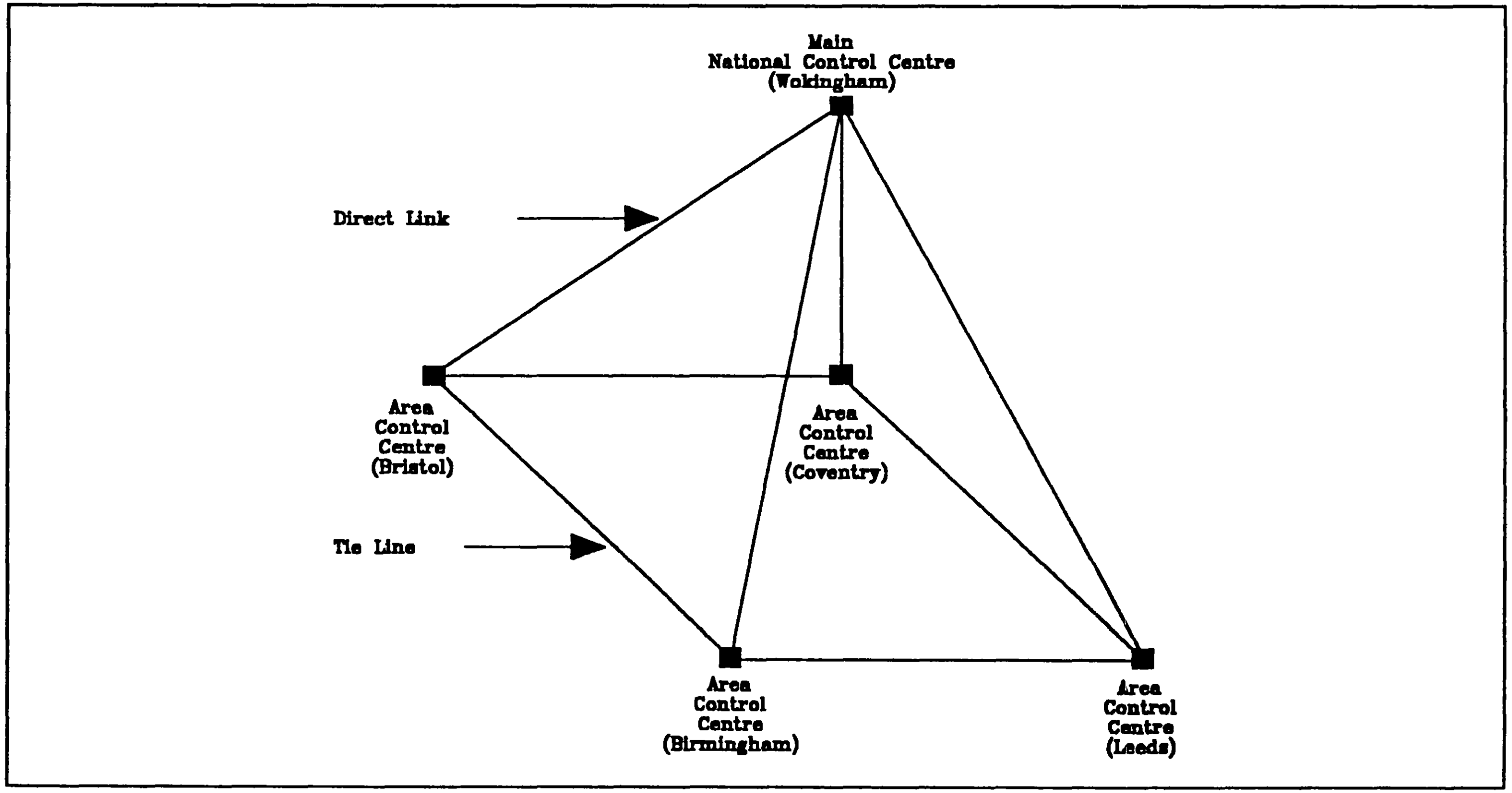

Figure 2.5 The Communications Infrastructure Between the NCC and the ACCs for the Power System of England and Wales

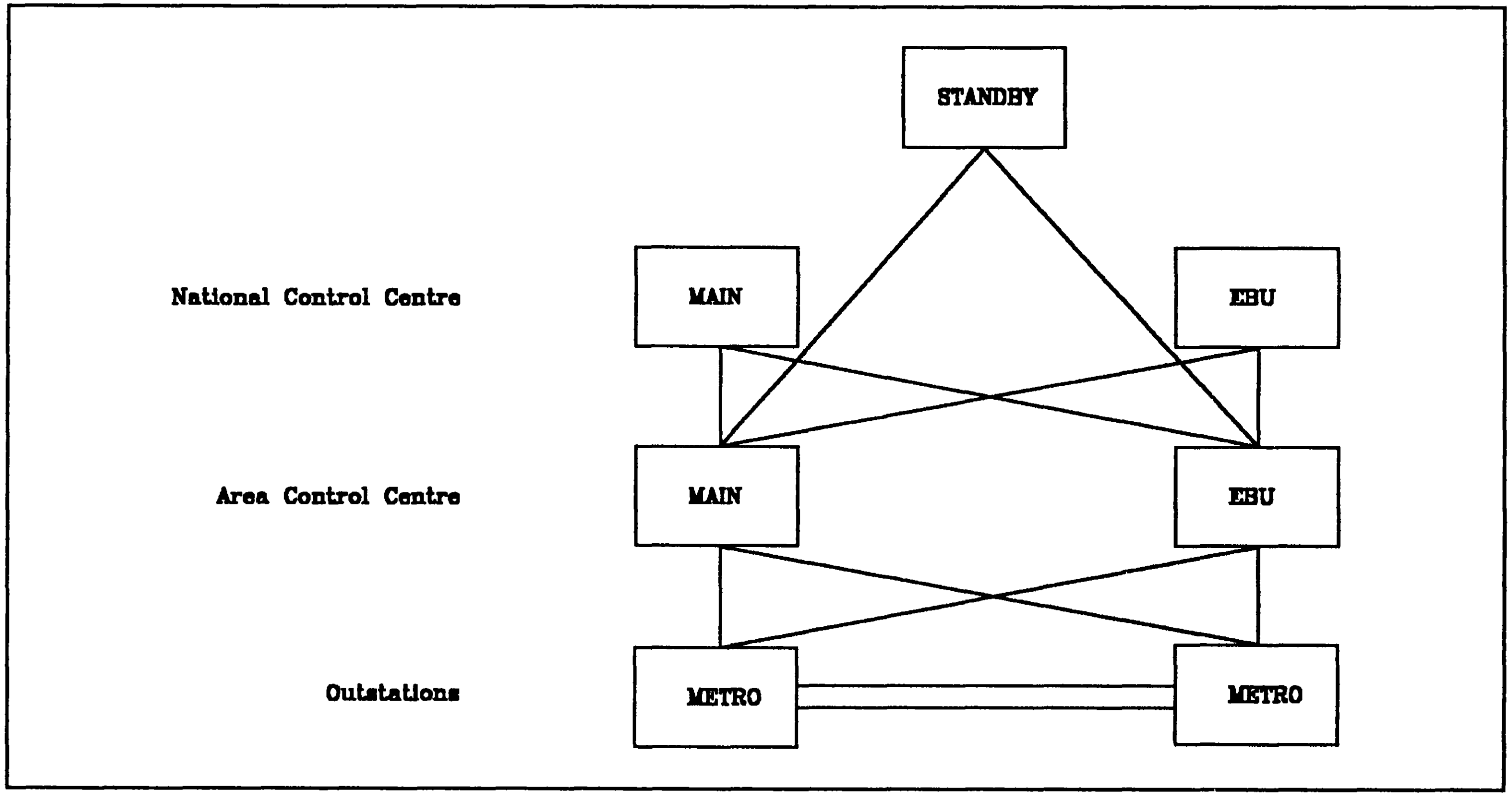

Figure 2.6 Overview of Monitoring and Control Communications for the Power System of England and Wales

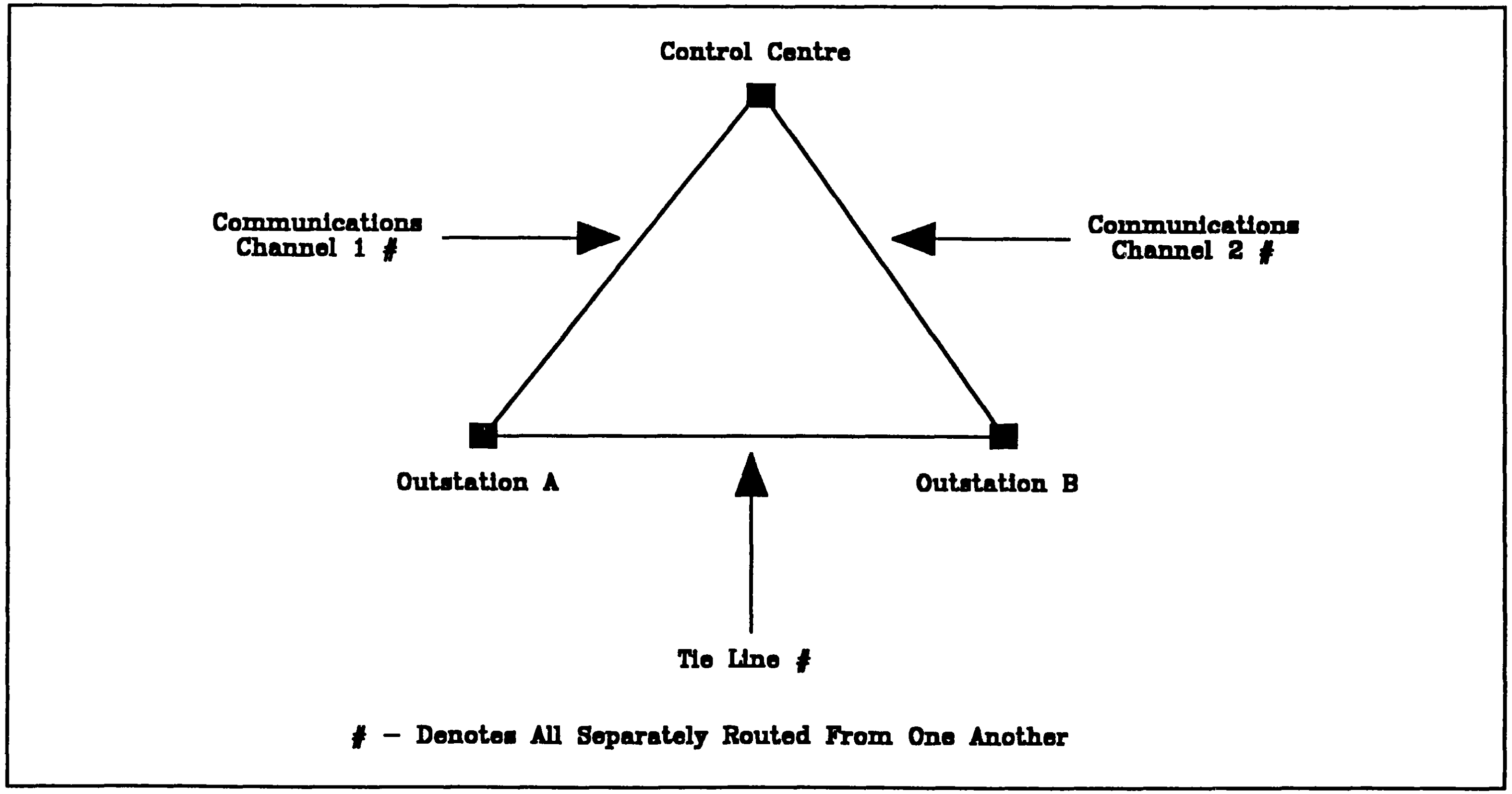

Figure 2.7 The Principle of Communications Between the ACCs and the METROs

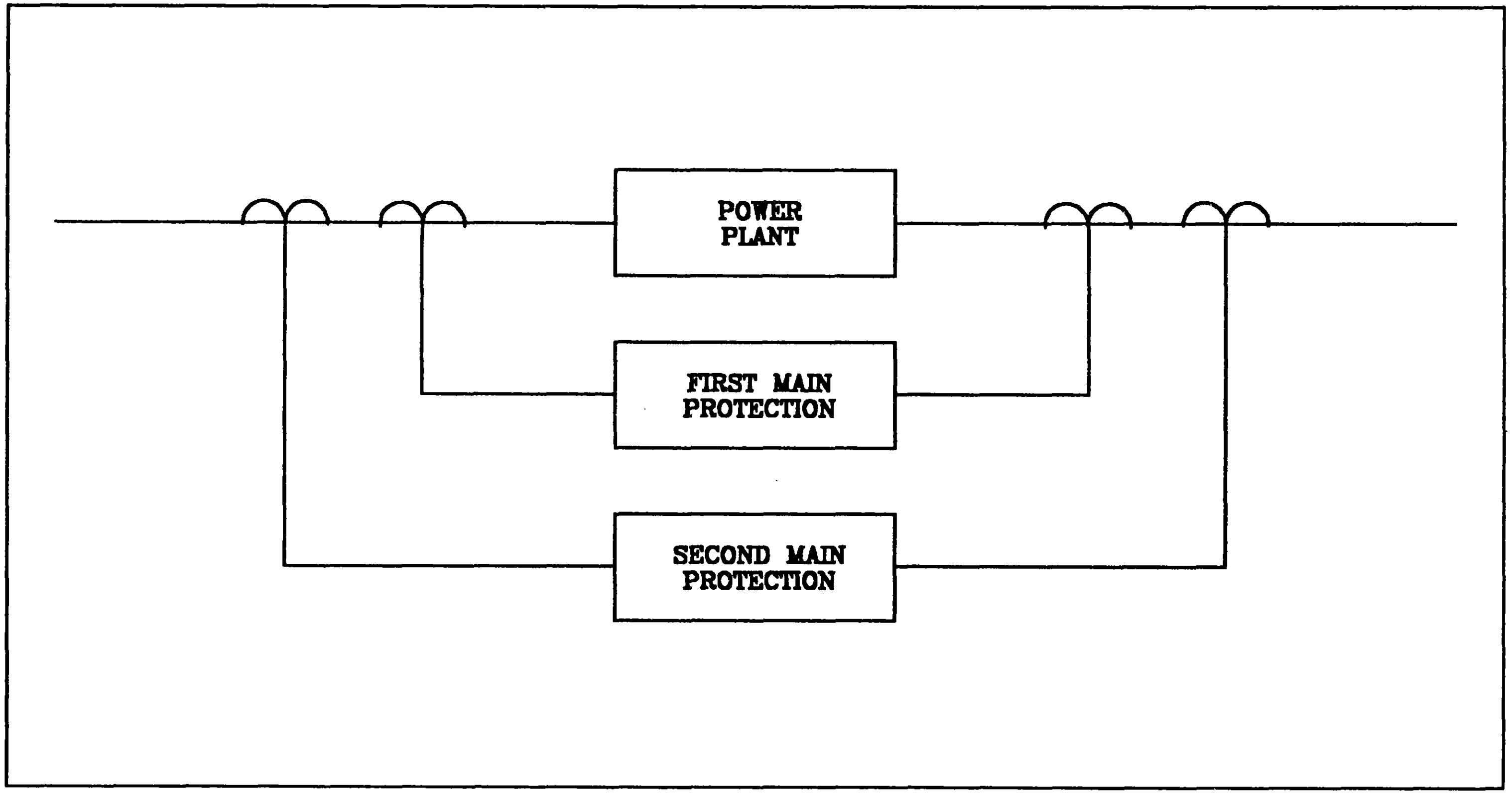

Figure 2.8 General Illustration of the Concepts of Protecting Power Plant

CHAPTER 3

COMPUTER INTEGRATED SYSTEMS

3.1 Introduction

During the first two decades of their existence, computers were large, highly centralised systems. Developments in microprocessor and communications technology during the 1960s led to significant changes in the way computer systems were organised and the demise of the large single computer. This resulted from the ability of the small microprocessor-based computer to be more easily placed next to the functions they were required to perform, ranging from small control and monitoring tasks to simple office tools. This enabled continued developments in the automation of functions involved in the direct assembly of commodities. However, it soon became apparent that the time taken to produce the 'physical' commodity, that had been benefitting from the automation of functions, only formed a small proportion of the entire process, the remainder of the time being accounted for by all the support functions required within the organisation. This realisation resulted in the development of tools for the automation of these support functions including not only payroll, sales, and design systems but also decision support systems. More importantly, it was recognised that central to the successful operation of a business was the communications between all the different aspects of the organisation. The successful business efficiently integrated [3.1, 3.2] all the different aspects of its business to respond to the market demands, produce better quality products, reduce costs, enhance performance, and maximise asset utilisation. For businesses to fully exploit the benefits of automation, this required not only the automation of functions but also the automation of how these functions were integrated. The computer, with its ability to easily form part of a computer network, formed the framework by which integration was to occur and led to the computer integrated system. These systems integrate the concepts from areas such as control, identification, estimation, communication theory, operational research, computer science and artificial intelligence to achieve this. The computer integrated system provides assistance, control and automation at all levels, and enables integration of all aspects of the business.

3.2 Structure of the Computer Integrated System

In its simplest form, a computer integrated system may be effected by a central computer, Fig.3.1 monitoring the business via sensors, using this information to calculate the required control actions necessary to optimise the performance of the business, and communicating these actions to the actuators. However as the system size increases, to analyze, control and optimise large centrally controlled systems in real time becomes impractical as the instrumentation, communication and computation requirements are too great. Issues of system reliability and integrity become increasingly important. Should the computer system fail, the entire system fails. Should the process require expansion, large programs require updating without introducing errors. Should problems arise in the software, trouble-shooting is difficult. Service requests are answered sequentially and when the computer is used to handle thousands of input and output requests, the speed at which the necessary control tasks are performed may be unacceptable and may result in integrity degradation.

An alternative approach is to decompose the centralised computing resource into a number of smaller decentralised computing resources, with each decentralised computer located next to the task or group of tasks it is required to monitor and control, Fig.3.2. In such a system, devices only have to feed their information back to their local computer. The decentralised computers democratically exchange information, to optimise the performance of the tasks they are required to perform, by communicating with one another. The decentralised computer system goes some way in alleviating the problems of the single centralised computer. Should one of the decentralised computers fail, the offending device can be isolated such that the remainder of the system is not affected. In some cases it is possible to re-route information through the decentralised computer system such that the effects of the failure are considerably reduced, if not eliminated. Expansion may easily be accommodated with small variations to software and the ability to add further decentralised systems. Comparatively small software systems are used making trouble shooting easier. The number of service requests undertaken by each decentralised computer is smaller making problems easier to isolate. These systems, do however still have size limitations dictated by the communications burden imposed on both the link and decentralised computers. As such, the integrity of the system cannot be guaranteed as the system expands.

This is overcome by creating a coordinating function, to remove the communication burden from the decentralised computer and supervise the required information flow between decentralised controllers resulting in a hierarchical structure, Fig.3.3. Hierarchical computer integrated systems have the advantages of decentralised systems, but are capable of controlling large systems, without loading of communications links as the system size increases. As the system size increases, further levels are added to the hierarchy and the functions within the hierarchy become very similar to those occurring within the classical hierarchically arranged organisation, Fig.3.4. Within the hierarchical system, the higher level subsystems have priority of action or right of intervention over lower levels. At the same time, the higher levels are dependent on performance of the lower levels and the information they feed back to enable them to make decisions. The functionality of the hierarchical computer system, as applied to power systems, is discussed in more detail in the following section.

3.3 Computer Integrated Systems for the Control and Protection of Power Systems

The control and protection of a large power system, say with dimensions shown in Table 2.1, whilst exploiting the benefits of the computer integrated system, must be effected by a hierarchical integrated computer system. In applying this to a large power system, the architecture of the hardware as shown in Fig.3.5 is derived. This is known as the integrated digital hierarchical control and protection system. The first level comprises of the system computer overseeing the entire control and protection system, whilst the remaining three levels of the hierarchical structure are derived by a top down natural decomposition of the power system into station host computer, bay level protection clusters, and switch yard resident data acquisition units. The functionality of each of the decentralised computers is briefly discussed here although the detailed implementation will be outlined in Chapter 7.

The system computer oversees the entire integrated digital hierarchical control and protection system. The substation station host computer communicates with the system computer and all adjacent substations to obtain information relating to the status of the system to enable the reduced model parameters to be calculated by the protection clusters. Information relating the current system status received from the protection clusters is communicated to the system computer and adjacent substation computers requiring this information. The protection clusters collate the data provided by the data acquisition units for use by the station computer and utilise the data provided by the station computer to adjust their respective setting values. The data acquisition units perform the necessary control functions on their associated circuit breakers and gather information directly from the system which is passed to the protection clusters via optical fibre communications link.

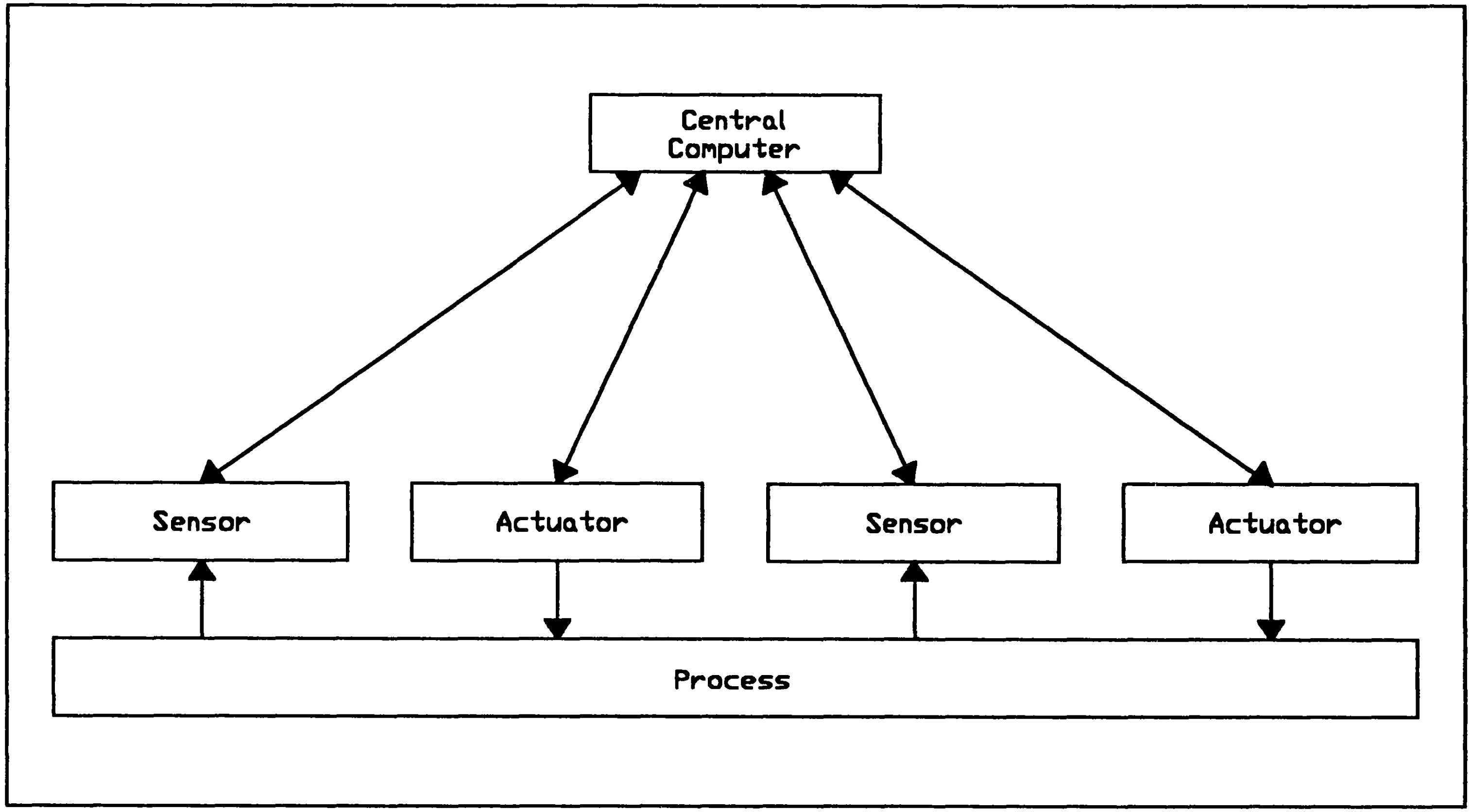

Figure 3.1 A Computer Integrated System Using a Central Computer

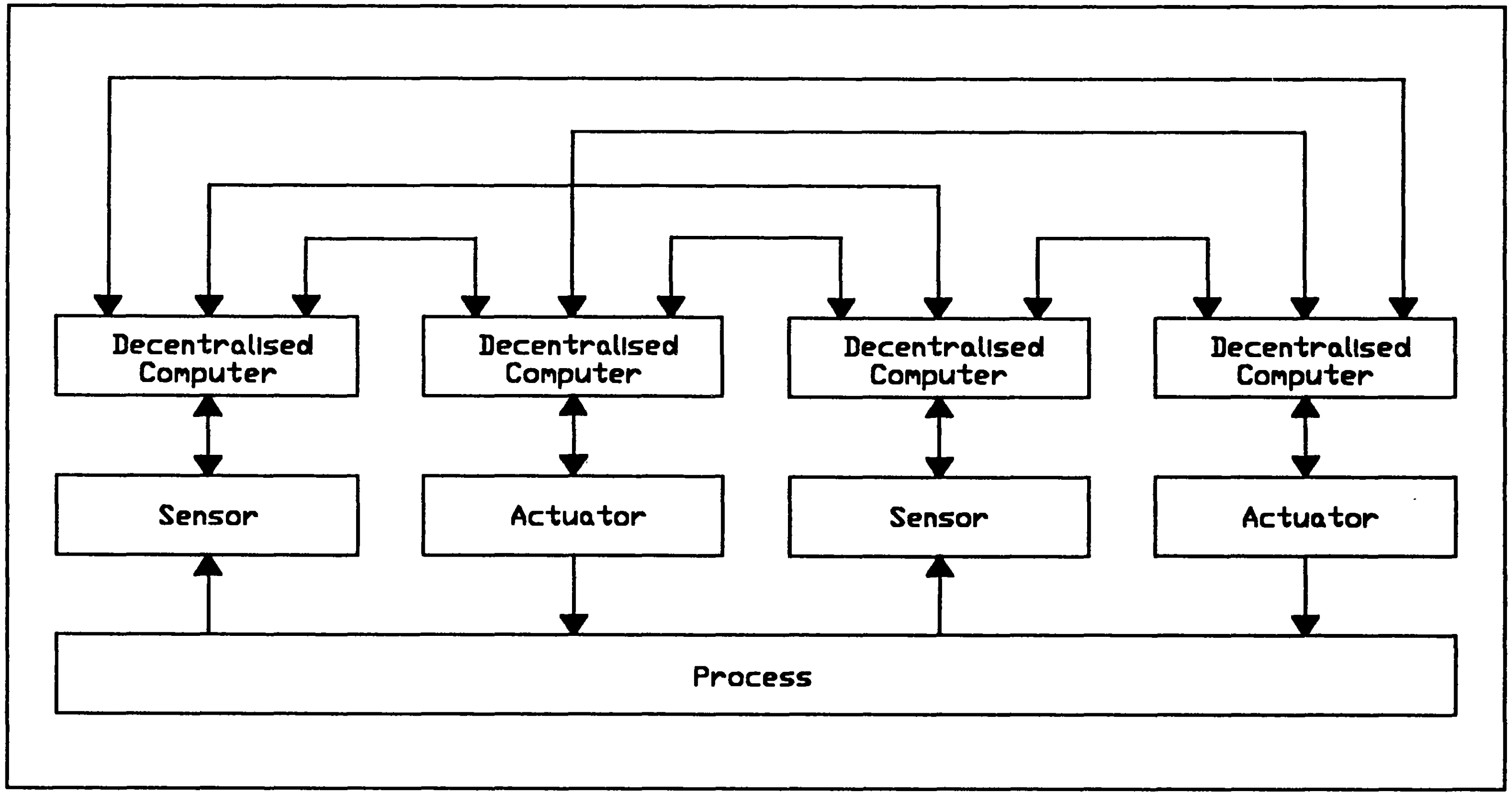

Figure 3.2 A Computer Integrated System Using Decentralised Computers

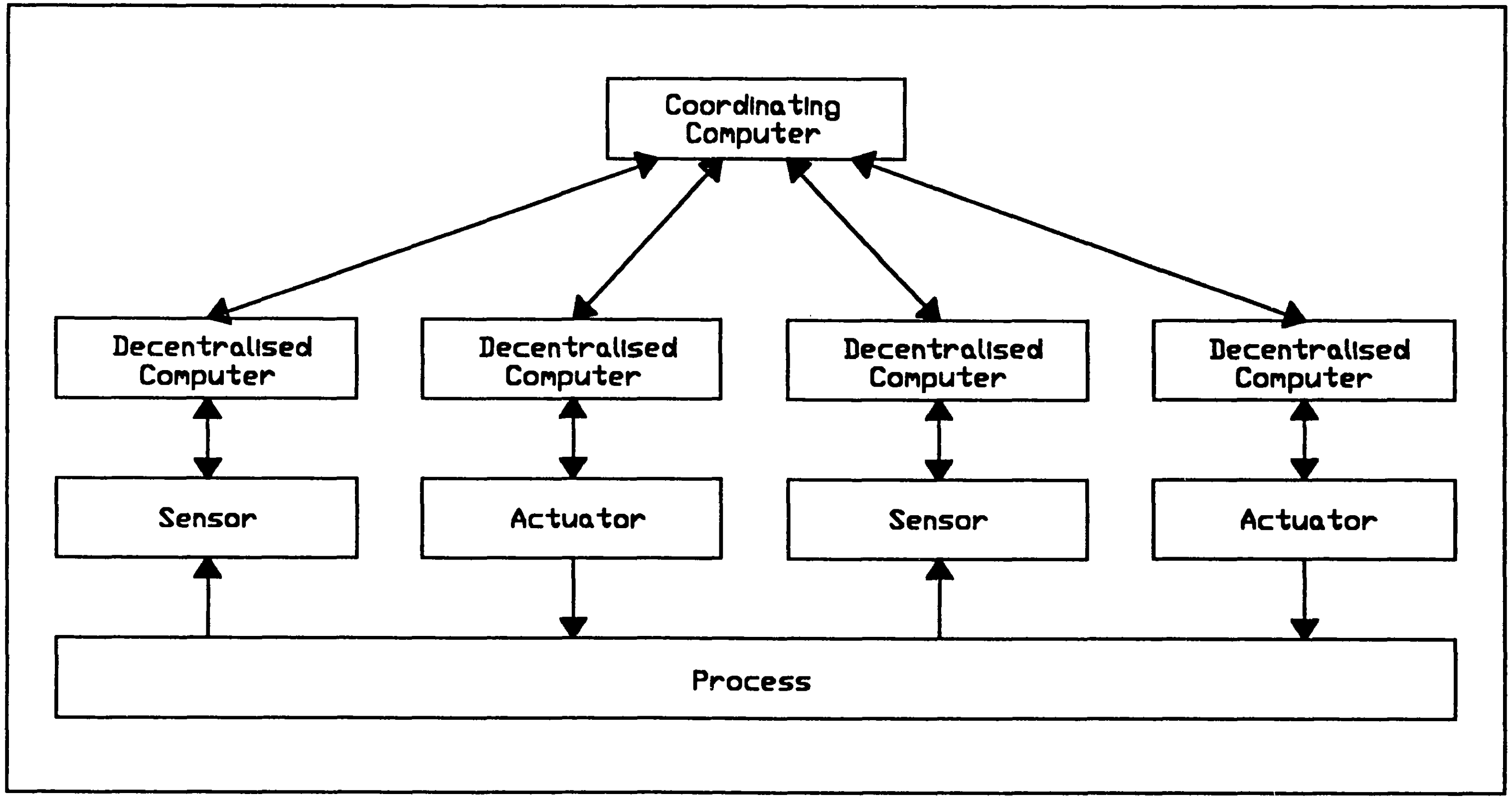

Figure 3.3 A Computer Integrated System Using Decentralised Computers Arranged Hierarchically

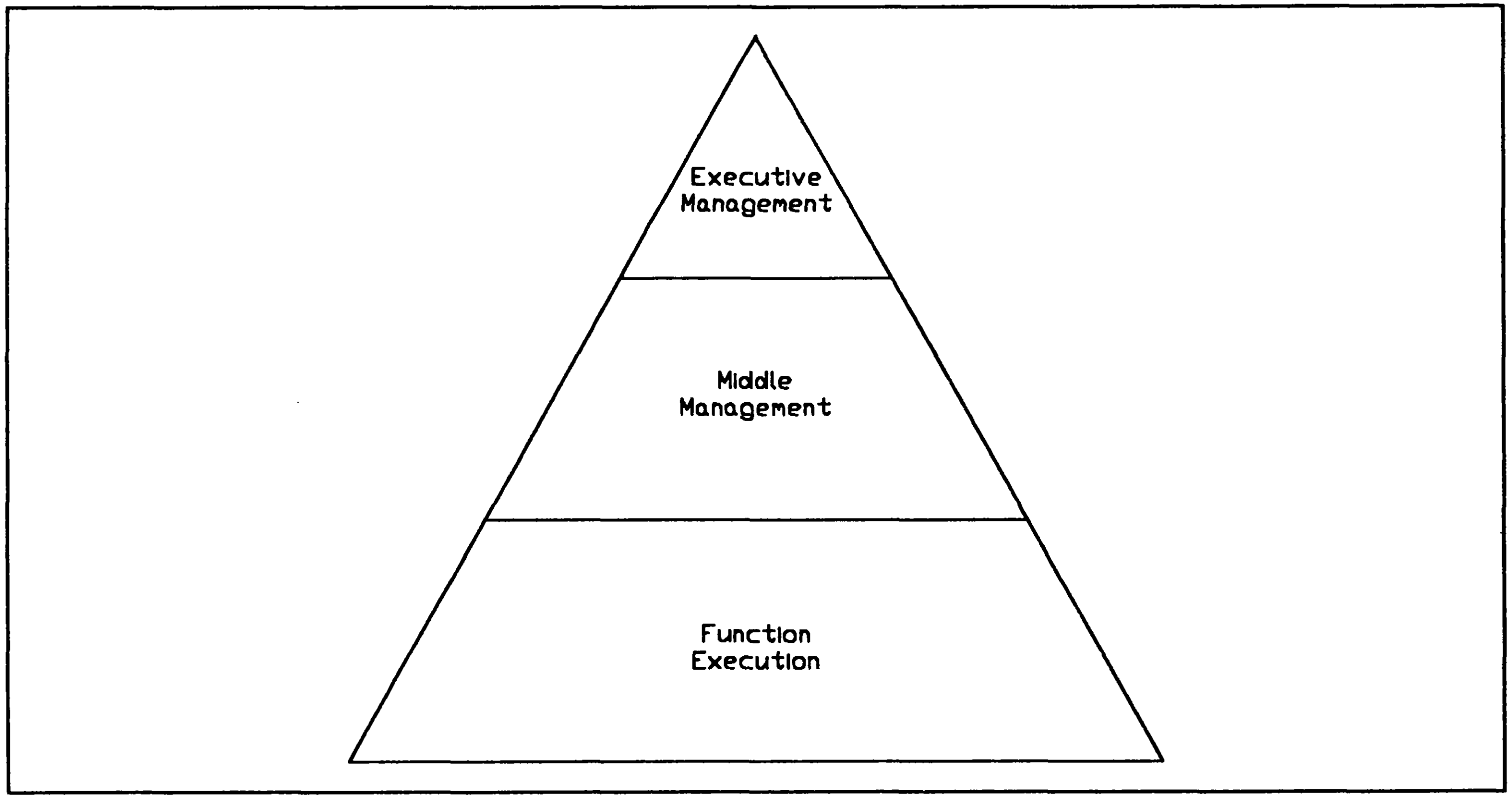

Figure 3.4 Overview of Functions Required to be Performed by the Computer Integrated System within the Business

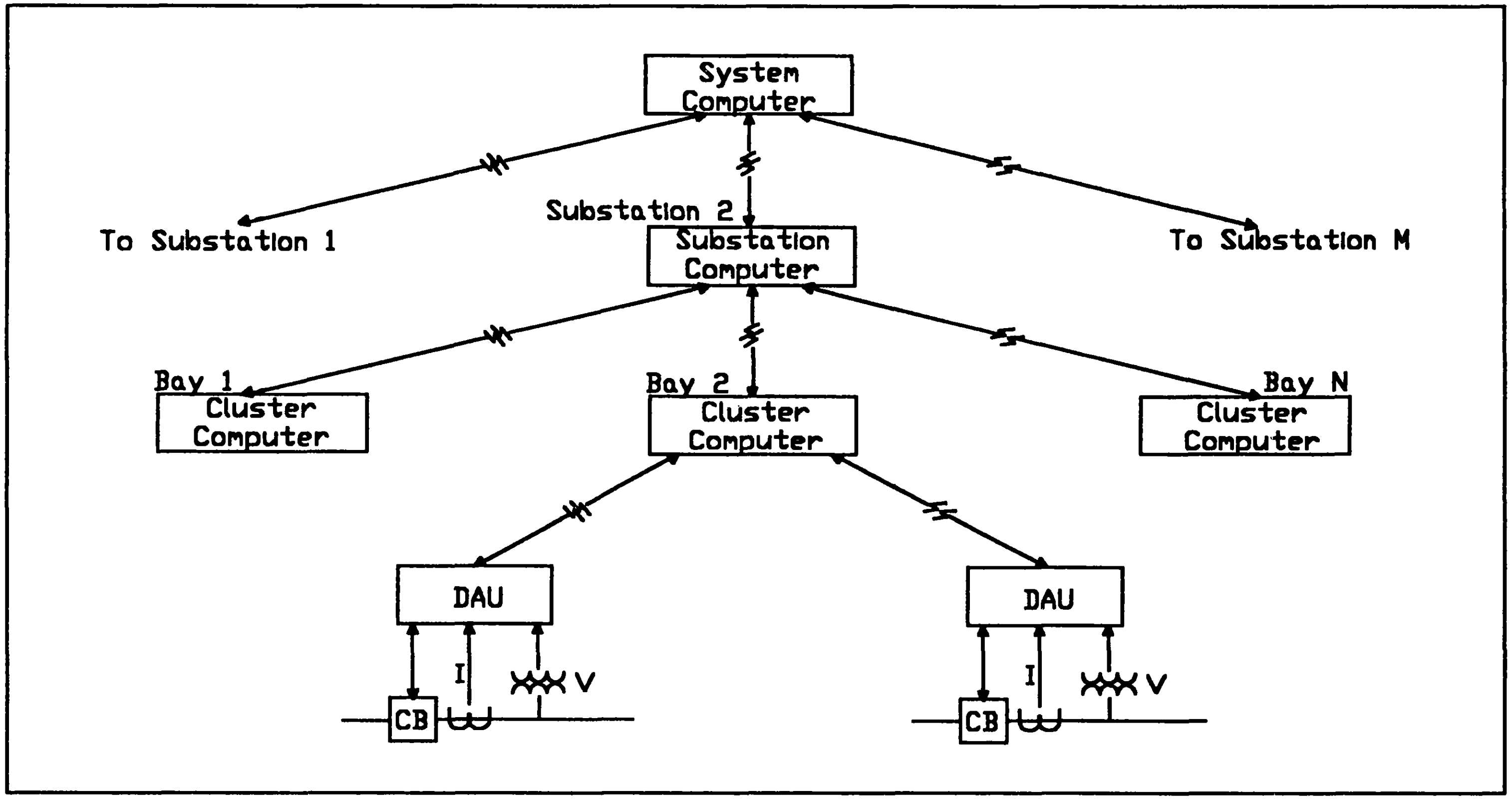

Figure 3.5 Architecture of the Hierarchical Control and Protection System

CHAPTER 4

ADAPTIVE PROTECTION AND CONTROL WITHIN A HIERARCHICAL SYSTEMS

4.1 Introduction

The integrity of the transmission network is closely correlated to the performance of the control and protection systems. To maintain, and if necessary increase, the performance of an evolving power system, techniques that improve the integrity of the protection and control functions in an economic manner are of considerable interest. The computer integrated system, by integrating information, provides a mechanism for performance enhancement. This chapter reviews the requirements for protection systems. The limitations of conventional protection are outlined and provide a framework for the introduction of an integrated digital hierarchical control and protection system for the optimisation of protection performance.

4.2 Requirements of Protection Systems

4.2.1 Introduction

The objective of protection is to maintain continuity of supply by the rapid isolation of faulted plant. This ensures minimum damage to all plant and reduces the effect of the fault on the remainder of the power system. Protection systems must be dependable, discriminative, economic and operate in a time to meet system dynamic requirements. The requirements of protection systems are outlined below.

4.2.2 Reliability Requirements

When a system fault occurs, protection is required to detect the fault rapidly and remove it from the system by initiating the opening of the associated circuit breaker. Protection located on adjacent plant will detect the fault, but must be able to discriminate between this fault and faults on the primary plant which they are designed to protect. This leads to the concepts of protection dependability and security [4.1].

- **Protection Dependability** is defined as a measure of the ability of the system protection to initiate circuit breaker tripping correctly.
- **Protection Security** is defined as a measure of the ability of the protection system to not operate incorrectly for faults on non-faulted sections of the system.

The requirements of dependability and security are mutually contradictory and methods should be found of optimising them. The reliability of the power system is quantified in terms of the dependability index, D_p, and security index, S_p [4.1]:

$$D_p = \frac{A - F_1}{A} \tag{4.1}$$

$$S_p = \frac{A - F_2}{A} \tag{4.2}$$

where:

A = total number of system faults.

F_1 = number of faults where there was a failure to trip the circuit breaker.

F_2 = number of faults on which there was an unwanted circuit breaker operation.

These are annually evaluated, with the dependability index having a typical value of 99.1% and the security index having a value of 97.3% [4.1].

4.2.3 Fault Clearance Time Requirements

The time period in which a fault is on the system has two effects:

- **Stress:** Under fault conditions, the components in the system undergo large stresses dependent on the current short circuit levels in the system. To avoid component degradation and possible damage, system faults must be removed as quickly as possible.

- **Stability:** Stability is influenced by the time constants and inertias of the power system components and the operating times of switch-gear and protection relays to remove faults. The longest time that a fault may remain on the system without the system going unstable is known as the critical clearing time (CCT). It is imperative to maintain stability through fault disturbances so that fault clearance times are less than the CCT, on the power system.

To retain system transient stability and avoid stressing system components, faults should be cleared as quickly as possible. Primary protection should clear faults within 80ms and back-up protection should aim to clear faults within 300ms [4.1].

4.2.4 Maximum Load Current Requirements

Protection systems installed should be designed to operate throughout the range of probable operational loadings including short time overload capabilities. Where constraints are identified, the cost of improving the protection system to the benefit of improved utilisation should be assessed.

4.2.5 System Management Requirements

In complex systems, the issues of management become far more complex. To keep out-of-merit operation of generation plant to a minimum, it is essential that maintenance and refurbishment programmes for the entire system coordinate with one another. In addition, these should be minimised.

4.3 Limitations of Conventional Protection Systems

4.3.1 Distance Protection

Changes in power system conditions influence the functionality of protection relays. For unit protection schemes, the influence of the power system state external to the protected unit is minimal, and techniques such as the bias setting have been used to optimise the performance. This is not the case for non-unit protection schemes, essentially distance relays, where changes in the power system operating conditions have a marked effect. The key effects and their causes are summarised below.

4.3.1.1 Multi-terminal Lines

It is well known that the measured impedance for a multi-terminal transmission system arrangement is dependent on the throttling point infeeds. The measured impedance of a relay at busbar A for a fault that is a proportion α along TB, Fig.4.1, is given by the expression:

$$Z_{measured} = Z_{AT} + \alpha.\frac{I_{AT} + I_{CT}}{I_{AT}}.Z_{BT} \tag{4.3}$$

This may be written more succinctly as:

$$Z_{measured} = Z_{AT} + \alpha.T.Z_{BT} \tag{4.4}$$

where T is the throttling or infeed ratio and is given by the expression:

$$T = \frac{I_{AT} + I_{CT}}{I_{AT}} \tag{4.5}$$

This illustrates that in teed feeder arrangements [4.2], the ideal zone 1 setting impedance is dependent on the variation of the fault current contribution of I_{CT} relative to I_{AT}. In a similar manner, the influence of the infeeds at the remote end of a protected feeder influences the backup zone setting values. To ensure correct relay operation it is necessary to either:

- place constraints on the operation of the power system.
- protect the system with unit protection schemes.
- ensure that the system has knowledge of the fault current infeed ratio.

4.3.1.2 High Resistance Earth Faults

For single end fed systems, earth fault impedance causes protection relay under-reach. This is illustrated by considering a phase to earth fault in a residually compensated phase to earth element of a distance relay. Using symmetrical component theory it can be shown that, for say an a-phase to earth fault, the measured impedance, $Z_{measured}$, to the fault point is given by the expression [1.46]:

$$Z_{measured} = \alpha . Z_{l1} + \frac{3 I_f R_f}{I_a + K_{res} I_{res}} \qquad (4.6)$$

Fig.4.2 shows how the impedance presented to the relay varies with changing fault resistance R_f. For high resistance earth faults, the impedance presented to the relay falls outside the characteristic resulting in the relay mal-operation. For double end fed systems [4.3] this is further exacerbated by the influence of the unknown remote end infeed. The issues of the correct operation of distance relays subjected to high resistance earth faults is considered in more detail in Chapter 6.

4.3.1.3 Pre-fault Loading

Pre-fault loading influences the operation of the distance relay in both pre-fault and fault conditions. The impedance presented to the a-phase to b-phase element of a distance relay is given by the expression:

$$Z_{measured_{a-b}} = \frac{V_a - V_b}{I_a - I_b} \tag{4.7}$$

The corresponding measured impedance presented to the a-phase to earth element of the residually compensated distance relay is:

$$Z_{measured_{a-e}} = \frac{V_a}{I_a + K_{res} I_{res}} \tag{4.8}$$

Under pre-fault operating conditions, both the phase to phase and phase to earth measured impedances show that an increase in pre-fault load current corresponds to a reduction in the measured impedance. This is illustrated in the impedance plane in Fig.4.3. For a mho type distance relay, continued load impedance reduction results in encroachment into the protection relay characteristic and subsequent relay mal-operation.

Under fault conditions, the pre-fault loading has the effect of redistributing the fault current in the network. This influences the infeed ratios which have repercussions as outlined in section 4.3.1.1.

4.3.1.4 Topological Variations

Under faulted network conditions, changes in topology alter the impedance path from the source to the fault point. The measured impedance, $Z_{measured}$, by the relay at busbar 1 for the system of Fig.4.4 representing a portion of a large network is given by the expression:

$$Z_{measured} = Z_{14} + \alpha . Z_{24} . \frac{I_{13} + I_{14} + I_3}{I_{14}} \tag{4.9}$$

In a large interconnected network, changes in topology may be represented by changes in Z_{13} resulting in changes in the current contribution I_{13} and redistributions of the fault current contributions in the feeders. These changes alter the ratio of I_{13} to I_{14} and hence influence the infeed ratio. As outlined in section 4.3.1.1 the infeed influences the apparent impedance measured at the relaying point. It should be noted that the influence of topological variations, especially in the local vicinity of the protected feeder, are large and of great importance in the determination of protection relay back-up setting values.

4.3.1.5 Mutual Coupling in Ground Impedance Protection

Mutual coupling, due to either double circuit transmission lines on the same tower or a number of parallel transmission lines using the same right of way, introduces a measured impedance error [4.4]. For an earth fault in one of the paralleled circuits, Fig.4.5.a, the fault current subdivides between the two circuits. The current flowing in one of the circuits induces a voltage in the adjacent circuit. The corresponding positive phase sequence and negative phase sequence mutual impedances between circuits are small enough to be neglected, although this is not the case for the zero phase sequence mutual impedance. Using equivalent circuit representation, Fig.4.5.b, the distance relay will measure a voltage $V_{measured}$ and current $I_{measured}$ given by the expressions:

$$V_{measured} = \alpha.Z_{l1}.\left[I_{C1} + I_{C2} + I_{C0}.\frac{Z_{l0}}{Z_{l1}} + I_{A0}.\frac{Z_{m0}}{Z_{l1}}\right] \tag{4.10}$$

and:

$$I_{measured} = I_{C1} + I_{C2} + I_{C0}.\frac{Z_{l0}}{Z_{l1}} \tag{4.11}$$

The measured impedance, $Z_{measured}$ will be:

$$Z_{measured} = \alpha . Z_{l1}\left[1 + \frac{I_{A0}}{I_{C0}} . \frac{Z_{m0}}{2.Z_{l1} + Z_{l0}}\right] \tag{4.12}$$

This illustrates that the relay will under-reach. For correct impedance measurement, to overcome the influence of mutual coupling, the measured relay current must be increased by:

$$I_{A0} . \frac{Z_{m0}}{Z_{l1}} \tag{4.13}$$

such that:

$$I_{measured} = I_{C1} + I_{C2} + I_{C0} . \frac{Z_{l0}}{Z_{l1}} + I_{A0} . \frac{Z_{m0}}{Z_{l1}} \tag{4.14}$$

and the measured impedance reflects the true fault position.

4.3.1.6 Source Impedance Ratio (SIR) Variations

The SIR is the ratio of source impedance to line impedance. The source impedance is a measure of the fault level at the relaying point and will vary dependent on the power system operating conditions, configuration and methods of earthing. For resistive faults, the measured impedance by the relay becomes a function of the remote end infeed as outlined in section 4.3.1.2 and dependent on the SIR at each end of the line significant errors can be introduced into the apparent impedance measured at the relaying point. On the UK transmission system, the SIR varies from about 0.1 (35 GVA source and 100 km line) to about 11.5 (5 GVA source and 10 km line).

4.3.1.7 Power Swings

When synchronous sources at either end of a feeder swing with respect to one another, Fig.4.6.a, the measured impedance, $Z_{measured}$, at the relaying point varies [4.5, 4.6, 4.7] in accordance with the relation:

$$Z_{measured} = [Z_{sm} + Z_l + Z_{sn}] \cdot \left[\frac{E_m}{E_n}\right] \cdot \left[\frac{(\frac{E_m}{E_n} - \cos\theta) - j.\sin\theta}{(\frac{E_m}{E_n} - \cos\theta)^2 + \sin^2\theta}\right] - Z_{sm} \qquad (4.15)$$

Fig.4.6.b illustrates how changes in θ can result in encroachment into the relay characteristic resulting in mal-operation.

4.3.1.8 Reliability

A relay setting is a compromise between the requirements of dependability and security

[4.8, 4.9]. Under light system loading, protection relays should ideally be biased towards dependability; the perceived need being to get the fault off the system as quickly as possible. However, under heavy loading, the in-advertent loss of a line caused by a false trip is far more serious. Under these circumstances protection system dependability is ideally sacrificed to ensure protection system security. The required level of dependability is usually achieved by the introduction of redundancy while the level of security is determined by the inter-locking between relays. In conventional protection systems, levels of redundancy and relay inter-locking are fixed resulting in modes of operation of the power system where protection reliability is less than optimal.

4.3.1.9 Operating Time Setting

Protection relay time settings are pre-set. However, there are scenarios, where it would be beneficial to vary this:

- **Optimise Dependability and Security Dependent on Fault Position:** To optimise dependability and security for a distance relay requires analysis of the fault position relative to the reach-point before making a trip decision. For faults well inside the boundary, the relay can operate immediately without the danger of mal-operation due to over-reach. For faults close to the boundary, the relay integrates fault values for a long time to overcome noise and ensure accuracy.

- **Optimise Dependability and Security Dependent on Fault Type:** Multi-phase faults may be detected more quickly than single phase to ground faults. Thus, by identifying the fault type, the decision to trip the relay may be made faster for some faults resulting in improved security and dependability.
- **Limit Stress and Avoid Instability:** See section 4.2.3.

4.3.1.10 Auto-Reclosure Time Setting

The optimum reclose time is dependent on the time taken for the secondary arc to extinguish [4.10, 4.11]. If the reclosure time is too short, reclosure will take place before arc extinction which may result in initiation of a further trip. Conversely, the time to reclose must not be excessive to ensure continuity of supply. In conventional auto-reclose schemes, the reclose time is set such that under changing power system conditions it is not always optimal.

4.3.2 Optimising the Performance by Adaptive Relaying in a Hierarchical Protection and Control System

Adaptive protection incorporates additional functionality to overcome the influence of changing power system conditions. The additional functionality is achieved by providing the relay with further information. The information may be derived either locally by more detailed analysis of the traditional current and voltage input measurands, or remotely by transmission to the relaying point of additional information. The information required is related directly to the system conditions resulting in protection relay mal-operation. The implementation of adaptive protection functions using either locally or remotely derived information are not new and have, to a limited extent, been exploited by the protection engineer. For example, the non-unit cross polarised mho distance relay, using traditional measurements, may adapt to improve earth fault coverage and ensure detection of close up faults by introduction of the polarising voltage derived from the healthy voltage phases.

The application of enhanced signal processing techniques and artificial intelligence has continued to improve the performance of the discrete stand-alone adaptive relay provided with the traditional input measurands of its conventional equivalent counterpart. However, the limited information available at the relaying point limits the performance enhancements possible. The second mechanism provides the relay with additional information relating to the current status of the entire power system. This additional information may be derived by information integration. As was shown in chapter 3, the hierarchical computer integrated system provides the ideal framework to undertake this.

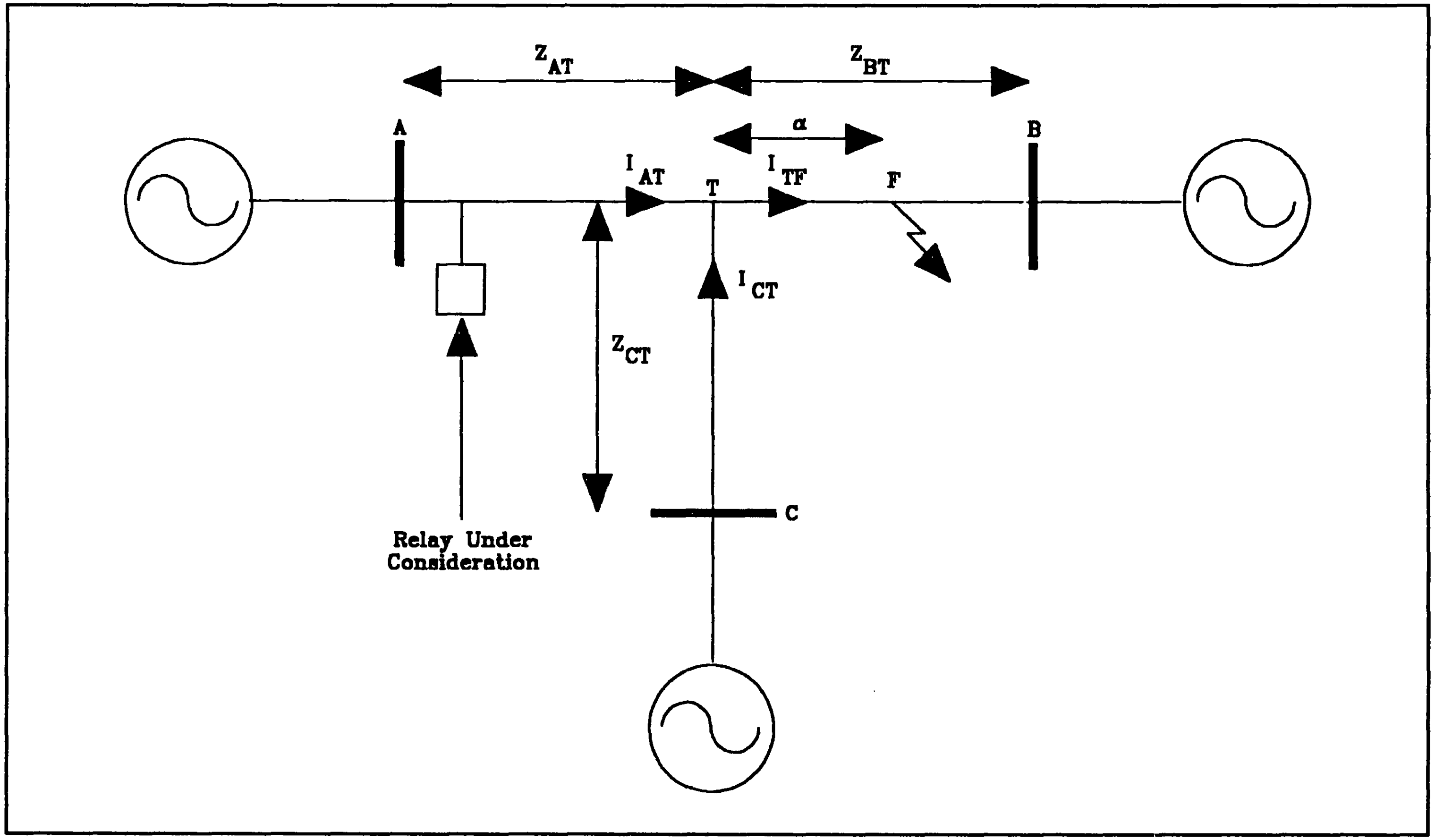

Figure 4.1 Influence of Infeed

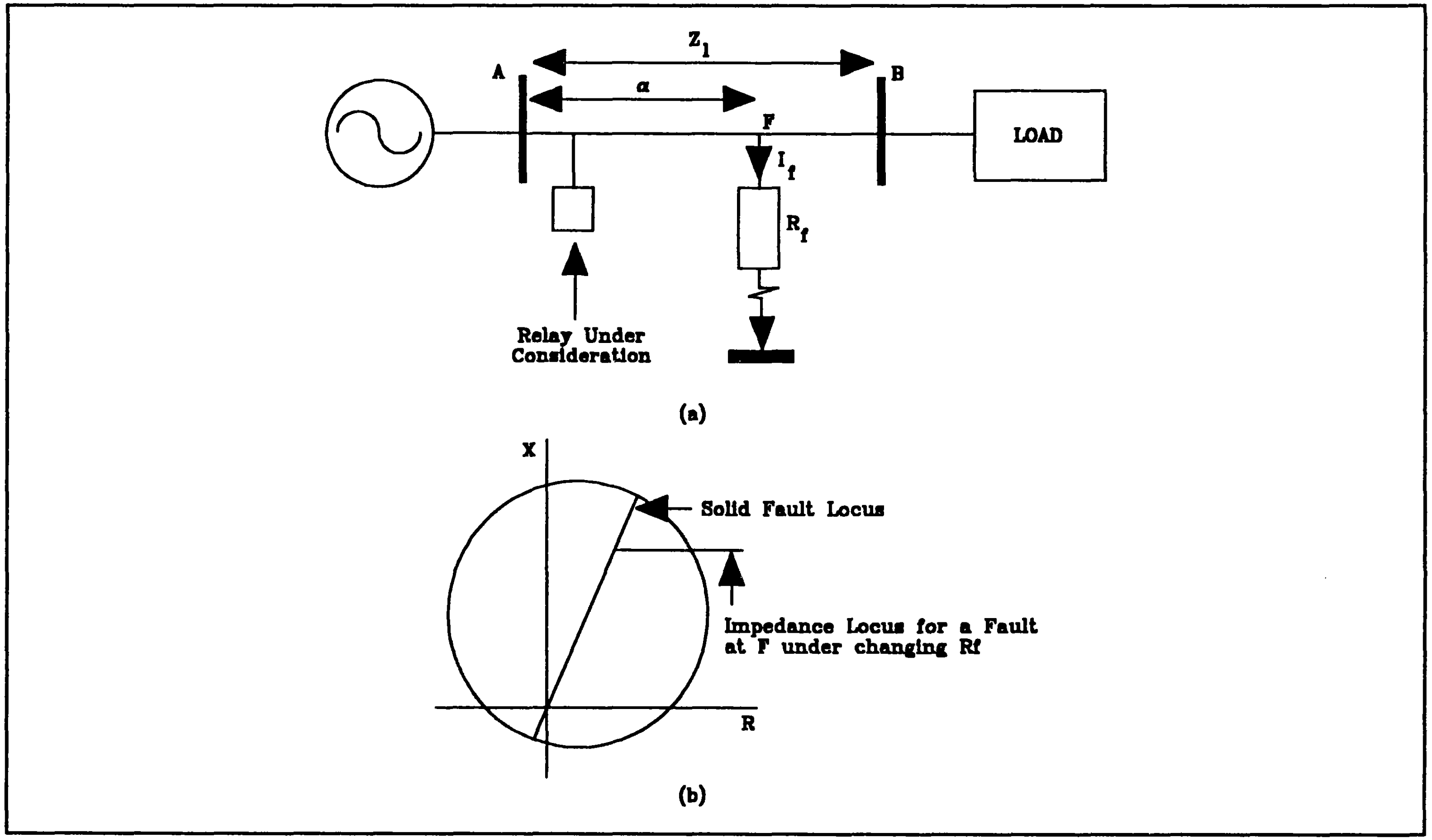

Figure 4.2 Influence of Earth Fault Resistance

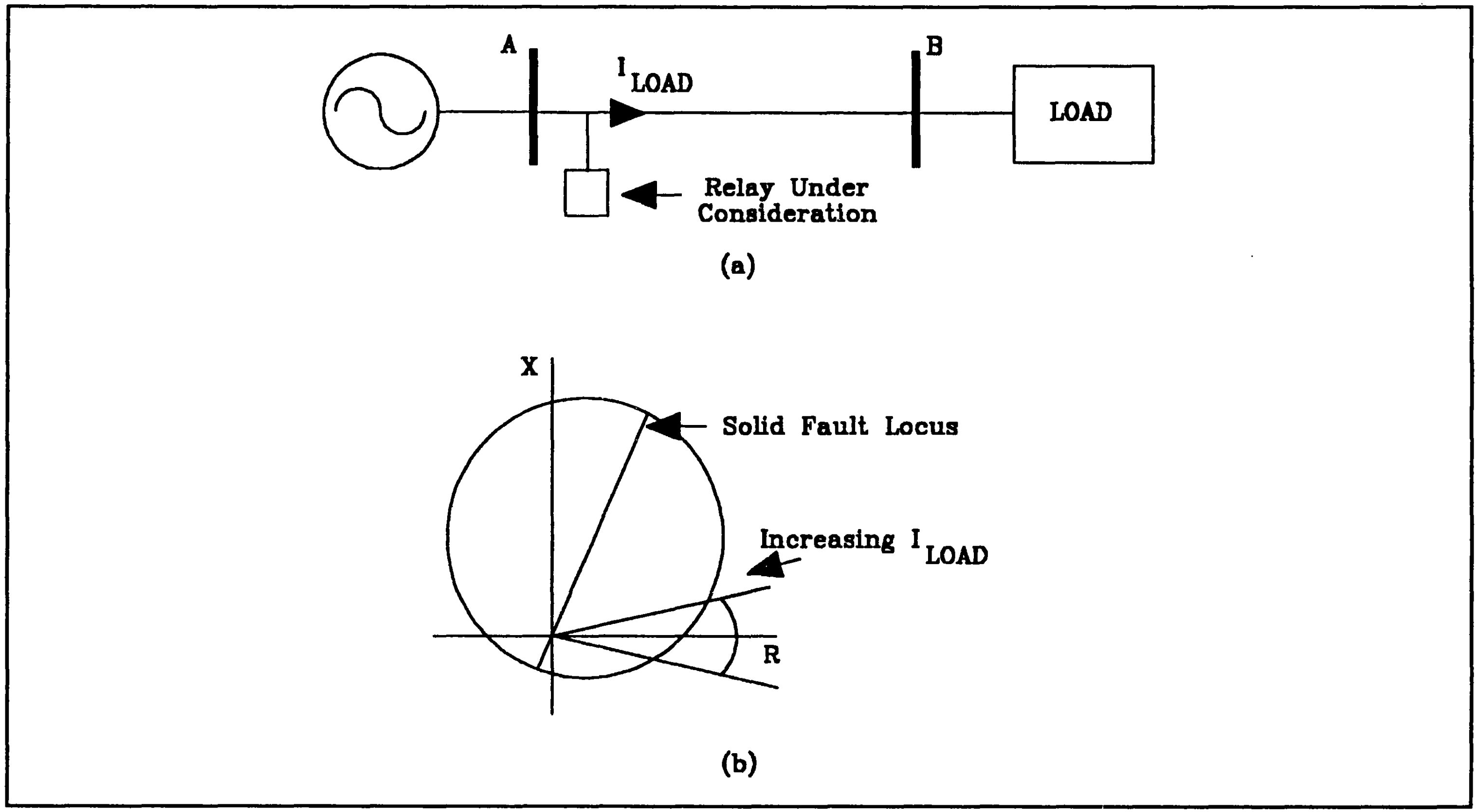

Figure 4.3 Influence of Load

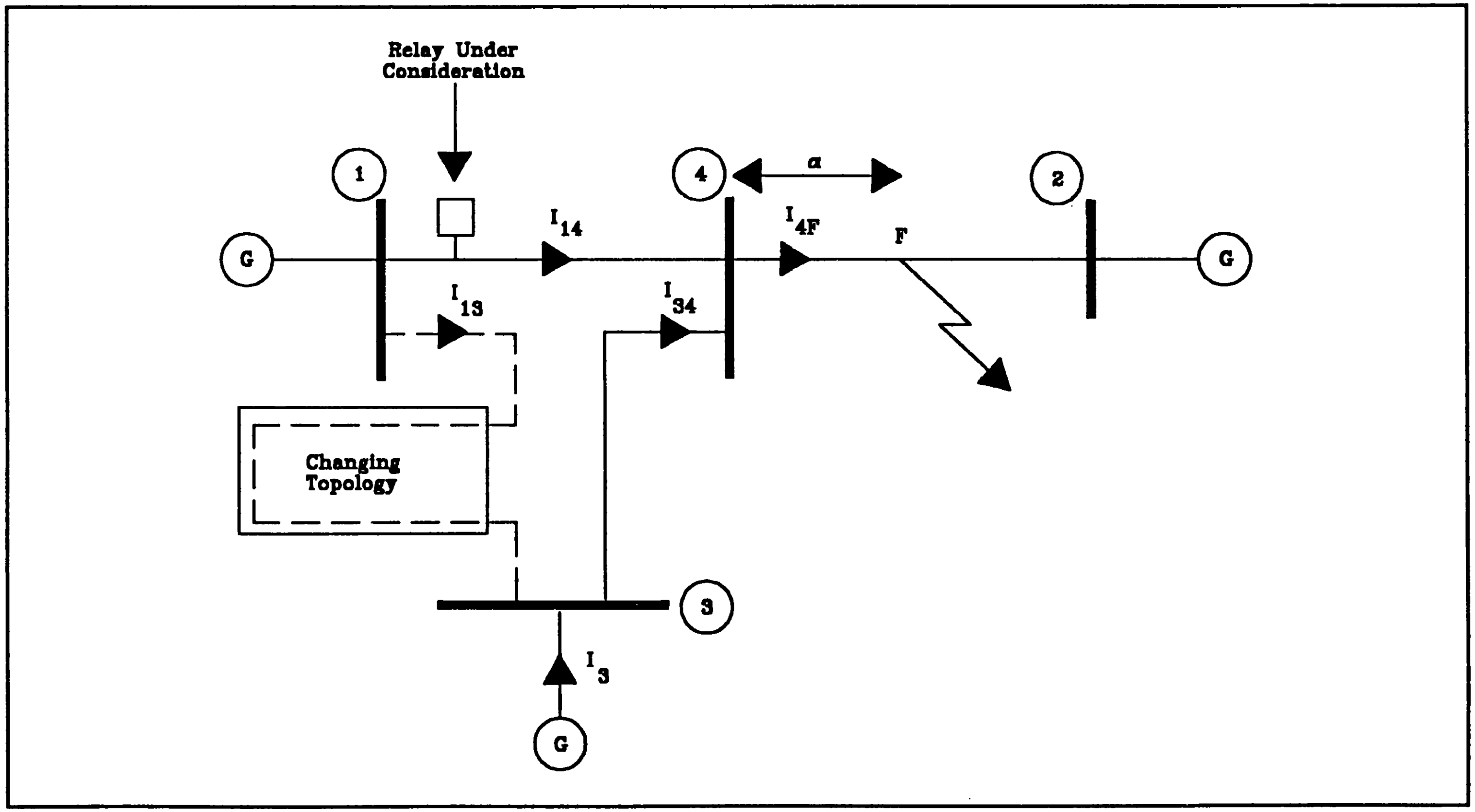

Figure 4.4 Influence of Topology

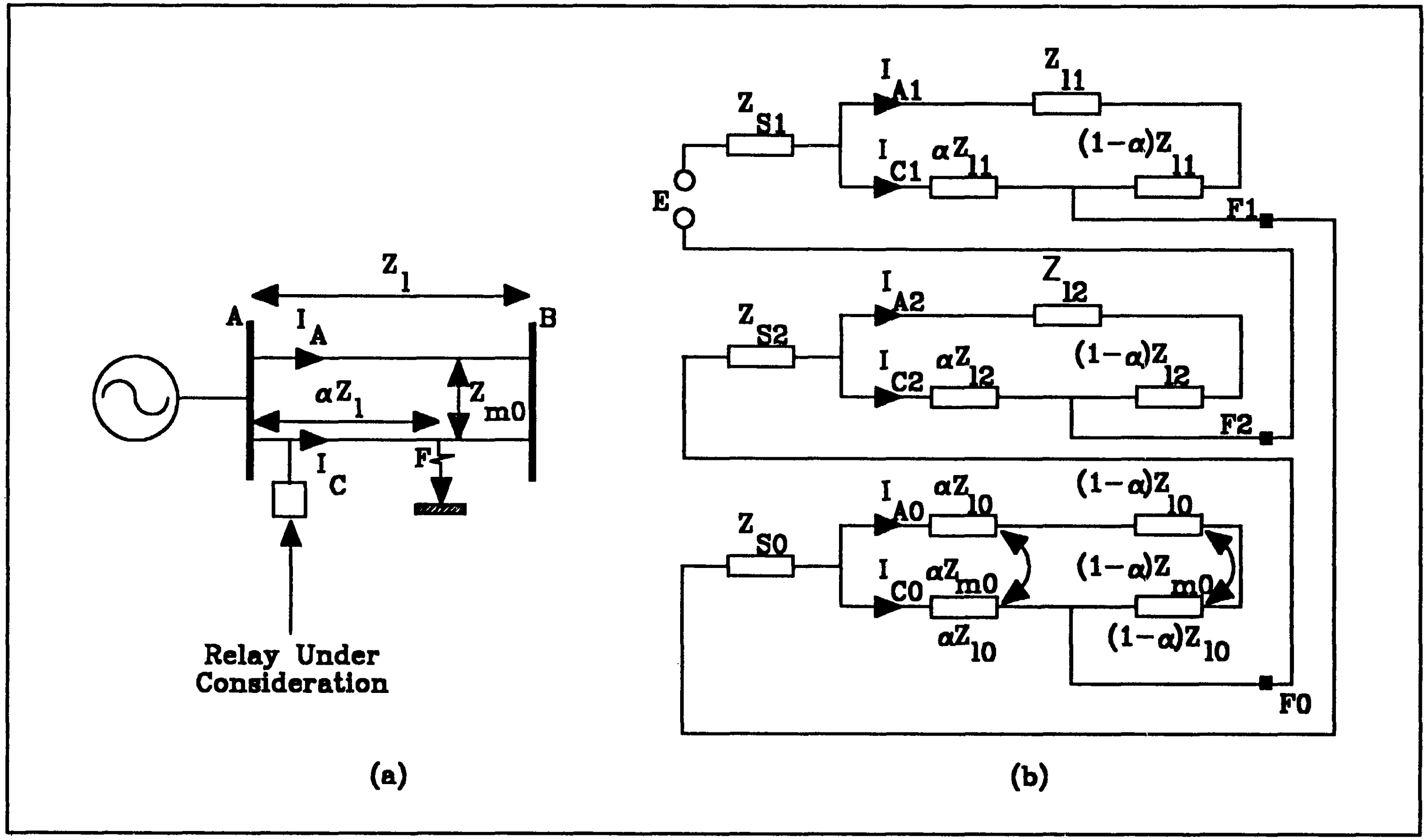

Figure 4.5 Influence of Mutual Coupling

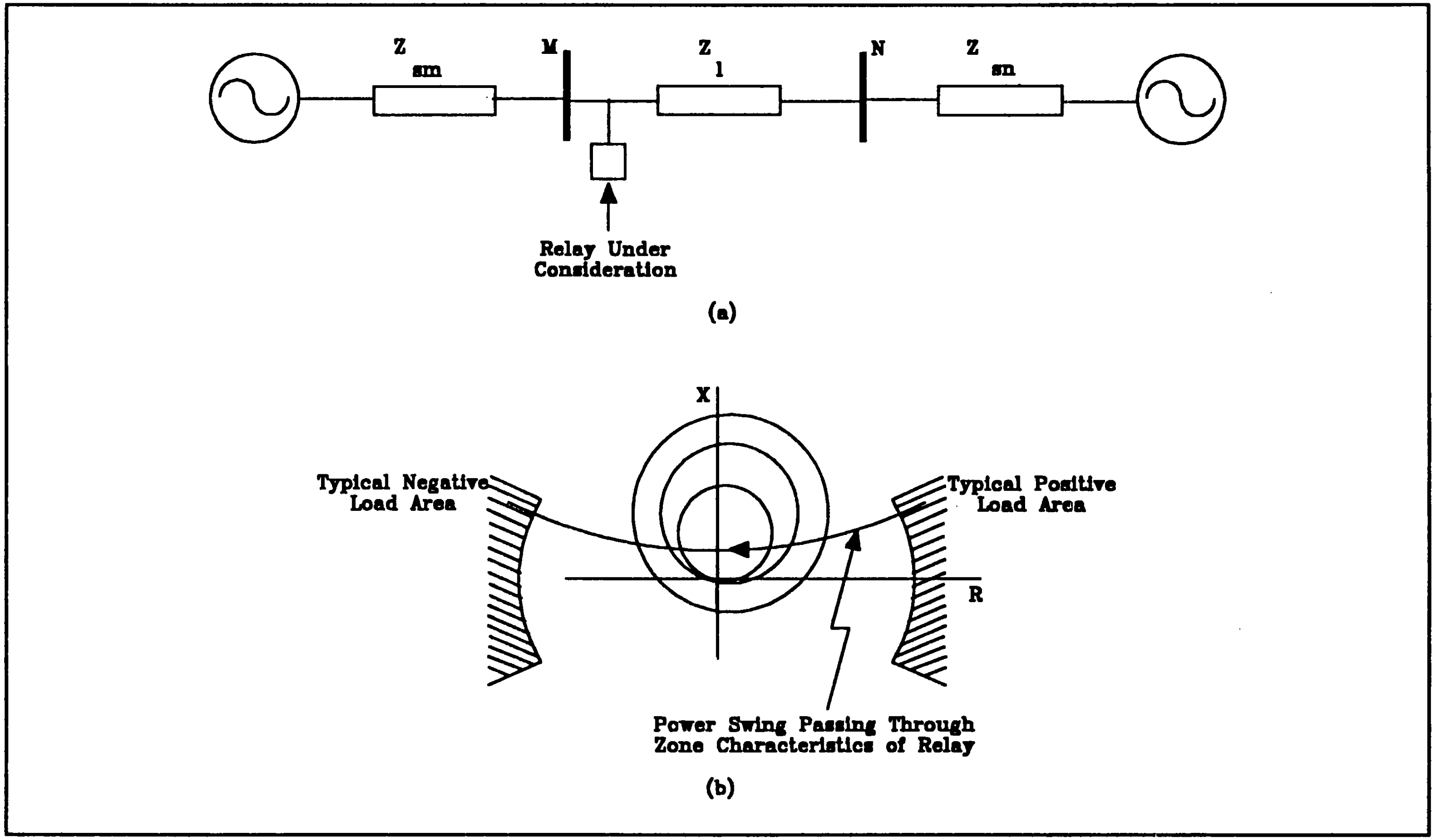

Figure 4.6 Influence of Power Swings

CHAPTER 5

OPTIMISATION OF DISTANCE RELAY BACKUP PERFORMANCE WITHIN AN INTEGRATED DIGITAL HIERARCHICAL CONTROL AND PROTECTION SYSTEM

5.1 Introduction

A relay setting is the main mechanism for the configuration of the protection relay. The setting of the protection relay has traditionally reflected the worst case fault scenario expected on the system and is based on the utilities' setting strategy, topology, assumed operating conditions and experience. For unit forms of protection, the influence of the power system operating conditions external to the protected unit are minimal and may be overcome by the use of bias settings. This is not the case for non-unit schemes, essentially distance relays, where the influence of the state of the power system, may leave the relay under-set or over-set. The strategy used for setting distance relays, by virtue of multiple zones, reflects this lack of information and aims to keep distance protection operating as optimally as possible. There are however, three scenarios where this is difficult to achieve:

- **Clearance of High Resistance Earth Faults in Zone 1:** Faults with resistance make the measured impedance at the relaying point a function of the unknown remote end infeed current.

- **Zone 1 Setting on Teed Feeders:** The setting of the zone 1 element on teed feeders is dependent on the fault current infeed contributions at the tee point.
- **Backup Settings (Zone 2 and Zone 3):** The setting of the backup zones is dependent on the fault current infeed contributions at the remote bus.

This chapter will concentrate on the last two of these. The issues for the correct operation of distance relays subjected to high resistance earth faults are considered in more detail in Chapter 6. For example, consider a relay located on the Wylfa to Pentir feeder at the Wylfa bus of the North Wales Grid System shown in Fig.5.1. The zone 3 setting for this relay, in accordance with the NGC setting strategy [5.2, 5.3] should be capable of seeing faults at the remote end of any line out of the substation at the remote end of the protected feeder, whilst avoiding load encroachment and over-reach into the distribution system. Fig.5.2 shows how the impedance measured by this relay varies as three phase faults are applied along Pentir to Deeside Feeder. Several curves are shown in Fig.5.2 for a variety of operating conditions together with the actual impedance from the relaying point to the fault. It is seen that changing the operational conditions has a large effect on the measured impedance thus making the optimum setting of the zone 3 reach difficult to calculate. Thus, to ensure continuing optimal relay operation, there is a need to constantly change or adapt the settings of the distance relays to reflect current power system conditions. It was shown in chapter 4 that adaptation may be effected by supplying the relay with further information, via say an integrated digital hierarchical control and protection system. The method by which this is achieved is outlined in the following section.

5.2. The Adaptive Setting of Protection Relays within a Hierarchical Control and Protection System

5.2.1 Background

The setting of a protection relay has traditionally been performed by the protection engineer based on assumed operating conditions, experience, the setting strategy and the power system configuration. More recently, the widespread availability of the computer has witnessed the emergence of software applications that model the power system and calculate the settings of protection relays. In its simplest form, the adaptive setting of protection relays within an integrated digital hierarchical control and protection system may be performed by having a computer model of the entire system at each of the relaying points within the system whose parameters were continually updated. However, as the size of the power system increases, the logistics of information transfer would become impractical. An alternative approach is to decompose the power system model into a number of power sub-system models where the integrated digital hierarchical control and protection system computer provides information relating to the influence of the remainder of the power system on each of the power sub-systems. Rockefeller et-al [1.49] were the first to describe how a simple impedance model (power sub-system model) of the power system, with up-to-date parameters relating to the current power system conditions was capable of improving protection reliability and maximising utilisation of the transmission system. The simple model should contain features enabling the correct adaptation of the protection relays functionality. For setting adaptation, the reduced model should include information that enables evaluation of the performance of the settings. For the case where the protection relays are of non-unit 3 zone distance type, it is beneficial for the reduced model, Fig.5.3, to retain the protected feeder parameters, all adjacent feeders out of the local substation, all adjacent feeders leaving the remote substation, and all feeders leaving the next but one substation for the correct setting of both primary and back-up functions. The reduced model requires information including:

- impedances and circuit breaker status of all feeders leaving the substation (including transformers). This enables evaluation of the performance of the zone 1 distance relay element and the reverse zone 3 reach.
- impedances and circuit breaker status of all feeders leaving the substation (including transformers) at the remote end of the protected feeder. This enables evaluation of the zone 2 and zone 3 elements of the distance relay.

- impedances and circuit breaker status of all feeders leaving the remote but one substation. This enables evaluation of the zone 3 element of the distance relay to ensure that it does not significantly over-reach.
- equivalent impedances representing the influence of the remainder of the system on the reduced model.
- pre-fault busbar voltages.

Using the reduced model, the fault conditions that reflect those corresponding to a similar fault in the actual system can be reconstructed. Traditional fault calculation requires the construction of the impedance matrix and evaluation of the fault currents with respect to pre-fault system conditions. To enable flexibility in the adaptive setting of protection relays, an impedance matrix is reconstructed.

5.2.2 Reconstruction of the Reduced Model Impedance Matrix

To enable the construction of the reduced model, consider the simple power system network with an admittance matrix of the form:

$$[Y]=\begin{bmatrix} Y_A & Y_B \\ Y_C & Y_D \end{bmatrix} \tag{5.1}$$

The reduced admittance matrix is obtained using the standard reduction technique [5.1]:

$$[Y_{REDUCED}] = Y_A - Y_B Y_D^{-1} Y_C \tag{5.2}$$

Under changing power system conditions, both the form and elements of the admittance matrix vary. For the system of Fig.5.4, the admittance matrix, subject to the operating condition where all circuit breakers are closed, has the form:

$$[Y] = \begin{bmatrix} Y_{11} & 0 & 0 & 0 & Y_{15} & 0 & 0 & 0 & 0 \\ 0 & Y_{22} & 0 & 0 & Y_{25} & 0 & 0 & 0 & Y_{29} \\ 0 & 0 & Y_{33} & Y_{34} & 0 & Y_{36} & Y_{37} & 0 & 0 \\ 0 & 0 & Y_{43} & Y_{44} & Y_{45} & 0 & 0 & 0 & 0 \\ Y_{51} & Y_{52} & 0 & Y_{54} & Y_{55} & 0 & 0 & 0 & 0 \\ 0 & 0 & Y_{63} & 0 & 0 & Y_{66} & 0 & 0 & 0 \\ 0 & 0 & Y_{73} & 0 & 0 & 0 & Y_{77} & 0 & Y_{79} \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & Y_{88} & Y_{89} \\ 0 & Y_{92} & 0 & 0 & 0 & 0 & Y_{97} & Y_{98} & Y_{99} \end{bmatrix} \tag{5.3}$$

For the arbitrary case where the reduced network for relay adaptation contains only busbars 1, 2, 3, 4 and 5, the reduced admittance matrix incorporating the effects of the remainder of network has the form shown below and illustrated in Fig.5.5. The system computer automatically formulates the reduced impedance model for the substation computer using search, matrix re-ordering and reduction techniques such that the model retains the features described in section 5.2.1 for relay adaptation.

$$[Y]=\begin{bmatrix} Y_{11} & 0 & 0 & 0 & Y_{15} \\ 0 & Y_{22} & Y_{23} & 0 & Y_{25} \\ 0 & Y_{32} & Y_{33} & Y_{34} & 0 \\ 0 & 0 & Y_{43} & Y_{44} & Y_{45} \\ Y_{51} & Y_{52} & 0 & Y_{54} & Y_{55} \end{bmatrix} \tag{5.4}$$

For a given fault, the directly reduced network fault conditions are directly comparable to those of the original system. This network not only has the required retained feeders in the network but also equivalent sources and fictitious interconnection feeders. Should the operating conditions change, for example the feeder between busbars 7 and 9 has been removed following the clearance of a fault, the reduced admittance matrix will change. The admittance matrix will have the form shown below and the equivalent network will be that of Fig.5.6.

$$[Y]=\begin{bmatrix} Y_{11} & 0 & 0 & 0 & Y_{15} \\ 0 & Y_{22} & 0 & 0 & Y_{25} \\ 0 & 0 & Y_{33} & Y_{34} & 0 \\ 0 & 0 & Y_{43} & Y_{44} & Y_{45} \\ Y_{51} & Y_{52} & 0 & Y_{54} & Y_{55} \end{bmatrix} \tag{5.5}$$

For the adaptive setting of distance relays, the parameters in the admittance matrix must be continually updated via the hierarchical structure. The derived admittance matrix, reflecting the current operating conditions, may then be inverted to obtain the impedance matrix:

$$[Z]=\begin{bmatrix} Z_{11} & Z_{12} & Z_{13} & Z_{14} & Z_{15} \\ Z_{21} & Z_{22} & Z_{23} & Z_{24} & Z_{25} \\ Z_{31} & Z_{32} & Z_{33} & Z_{34} & Z_{35} \\ Z_{41} & Z_{42} & Z_{43} & Z_{44} & Z_{45} \\ Z_{51} & Z_{52} & Z_{53} & Z_{54} & Z_{55} \end{bmatrix} \tag{5.6}$$

With knowledge of the pre-fault busbar voltages, short circuit analysis may be performed for calculating the faulted network busbar voltages and branch currents using the well developed power system analysis techniques. The faulted network data then enables adaptive protection relay setting and evaluation.

5.2.3 Setting the Protection Relays in the Adaptive Environment

The settings of protection relays have traditionally been performed in accordance with a setting strategy. Within the hierarchical control and protection system, a number of strategies have been tried some of which are based on the NGC strategy and others being based on analysing the performance of the protection. The various setting strategies are outlined below. To provide a basis on which to compare the performance of the various strategies, the first of the strategies listed below is not in fact a strategy but the actual settings of the system:

1) **Actual NGC Settings:** These settings are user specified settings such as those that might currently be on the system. These may have been determined by a strategy such as that of NGC [5.2, 5.3] in accordance with the following:

- Worst case power system operating conditions.
- Protection engineer experience.

2) **Adaptive NGC Strategy Settings:** These settings have been calculated in strict accordance with the NGC setting strategy. Whereas the actual NGC setting reflects worst case power system operating conditions, this adaptive setting reflects the current operating conditions and enables consideration of the influence of the current:

- Topology.
- Short Circuit Levels.

3) **Adaptive NGC Strategy with Zone 3 Setting Using Actual Throttling Factor:** The

NGC Setting Strategy conditions the remote end throttling factor dependent on the topological configuration at the remote busbar associated with the protection. This setting is similar to that of (2) but instead of using the conditioned throttling factor, the actual throttling factor is used.

4) **Adaptive NGC Strategy with Zone 3 Setting Using Actual Throttling Factor and Constrained By Current Loading:** Conventional protection is set to avoid incorrect operation due to worst case load encroachment. However, often the load impedance is far less constraining than the worst case load impedance. This setting exploits this by constraining the setting in accordance with the actual load and not the worst case load. In addition, the actual throttling factor, as opposed to the conditioned throttling factor is used.

5) **Adaptive Setting Optimised For Maximum Dependability but constrained by Worst Case Loading:** The Zone 3 Setting is ideally required to clear faults at all busbars at the remote end of all feeders leaving the substation at the remote end of the protected feeder. This setting maximises the dependability of the Zone 3 Setting to ensure this occurs, subject to worst case load encroachment.

6) **Adaptive Setting Optimised For Maximum Security but constrained by Worst Case Loading:** Whilst the Zone 3 Setting is ideally required to clear faults at all busbars

at the remote end of all feeders leaving the substation at the remote end of the protected feeder it should not operate for faults at any other busbars within the system. This setting maximises the security of the Zone 3 Setting, subject to worst case load encroachment .

7) Adaptive Setting Optimised For Minimum Mal-operation (Incorrect Operation + Failures to Operate) with Dependability Bias but constrained by Worst Case Loading: This setting minimises the number of mal-operations by considering both the security and dependability requirements. Should a scenario arise in which two different settings minimise the number of mal-operations, the larger is chosen to minimise the number of failures to operate. This is subject to worst case load encroachment.

8) Adaptive Setting Optimised For Minimum Mal-operation (Incorrect Operation + Failures to Operate) with Security Bias but constrained by Worst Case Loading: This setting minimises the number of mal-operations by considering both the security and dependability requirements. Should a scenario arise in which two different settings minimise the number of mal-operations, the smaller is chosen to minimise the number of incorrect operations. This is subject to worst case load encroachment.

9) Adaptive Setting Optimised For Maximum Dependability but constrained by Actual Loading: The Zone 3 Setting is ideally required to clear faults at all busbars at the remote end of all feeders leaving the substation at the remote end of the protected feeder. This setting maximises the dependability of the Zone 3 Setting to ensure this occurs, subject to actual load encroachment.

10) Adaptive Setting Optimised For Maximum Security but constrained by Actual Loading: Whilst the Zone 3 Setting is ideally required to clear faults at all busbars at the remote end of all feeders leaving the substation at the remote end of the protected feeder it should not operate for faults at any other busbars within the system. This setting maximises the security of the Zone 3 Setting, subject to actual load encroachment.

11) Adaptive Setting Optimised For Minimum Mal-operation (Incorrect Operation + Failures to Operate) with Dependability Bias but constrained by Actual Loading: This setting minimises the number of mal-operations by considering both the security and dependability requirements. Should a scenario arise in which two different settings minimise the number of mal-operations, the larger is chosen to minimise the number of failures to operate. This is subject to actual load encroachment.

12) Adaptive Setting Optimised For Minimum Mal-operation (Incorrect Operation + Failures to Operate) with Security Bias but constrained by Worst Case Loading: This setting minimises the number of mal-operations by considering both the security and dependability requirements. Should a scenario arise in which two different settings minimise the number of mal-operations, the smaller is chosen to minimise the number of incorrect operations. This is subject to worst case load encroachment.

Details of the reasoning behind the setting of relays in accordance with these methodologies are explained in the following sections.

5.3 Results

To analyse the performance of the adaptive settings, the North Wales 400 / 275 kV Grid System has been used. The power system operating conditions within the North Wales System, correspond to the predicted 1994/95 Winter Peak. All power system operating conditions and data are summarised in Appendix A. Based on this data, a number of adaptive settings have been calculated and the relative performance of each of the settings for faults at busbars throughout the network categorised in terms of failures to operate and incorrect operations. The relative performance of the individual setting strategies is illustrated in Fig.5.7.

5.4 Analysis of Results

5.4.1 Introduction to Adaptive Setting

The actual NGC settings (Setting 1) have been determined by the strategy and have been set to operate for faults based on the worst case power system operating conditions. For any other operating condition, this may leave the relay under-set or over-set. By using the NGC strategy in an adaptive manner (Setting 2), variations in operating conditions, caused say by changes in topology and short circuit levels, can be accommodated subject to conditions imposed by the strategy such as distribution system over-reach constraint, throttling factor conditioning, and load constraint. The last two conditions form the basis of a further two setting strategies, and as such will shortly be discussed. The first condition, distribution system over-reach, is optimised by the introduction of the adaptive algorithm based on Setting 2. For example, consider the setting of the zone 3 element of the Deeside to Legacy feeder at the Deeside busbar, the salient features being represented in Fig.5.8. To simplify the calculations, it will also be assumed that the impedances of the transformers are the same and given by Z. To avoid distribution system over-reach, it is required that the relay does not operate for faults at the Legacy 132 kV busbar. Should one of the transformers at Legacy be taken out of service, say following a fault or due to maintenance requirements, the impedance between the Legacy 400 kV busbar and the Legacy 132 kV busbar increases from Z/4 to Z/3. This increase in impedance, arising from a topological variation reduces the distributions system over-reach constraint and may be exploited by adaptive schemes.

5.4.2 Alterations to the NGC Strategy for Relay Adaptation

The NGC setting strategy constrains the settings to avoid load encroachment and distribution system over-reach. Whilst proving a highly successful method of avoiding the aforementioned problems, relay mal-operation can be introduced by the failure of the zone 3 element of relays to clear faults at the remote busbar out of the next substation. As such, for certain operating conditions, irrespective of the introduction of adaptive algorithms, the performance of the protection system cannot always be improved. This is illustrated in Fig.5.9 by considering the Legacy to Deeside Feeder at the Legacy Busbar which fails to clear faults at the Capenhurst 275 kV busbars, Pentir 400 kV busbar, Trawsfynydd 400 kV mesh corner, and Daines 400 kV busbar using both actual and adaptive settings. However, there are three areas where relaxation of the conditions in the setting strategy could improve the performance of the adaptive protection system resulting in advantages of implementation of adaptive schemes over conventional schemes:

- The setting of protection relays using the actual throttling factor at all times (ie: Setting 3 - see section 5.4.2.1).
- The setting of protection relays constrained by actual load and not worst case load (ie: Settings 4, 9, 10 and 11 - see sections 5.4.2.2 and 5.4.2.3).
- The setting of protection relays to detect faults appearing in negative quadrants in the impedance plane (see section 5.5.2).

5.4.2.1 The Setting of Protection Relays using the Actual Throttling Factor.

The setting of zone 3 elements of protection relays in accordance with the NGC strategy is subjected to conditioning of the throttling factor at the remote bus of the protected feeder in the following manner:

- Should the number of feeders into the remote substation of the protected feeder be less than 4, it is assumed that the throttling factor is 1.0.
- For protected feeder arrangements where the number of feeders into the remote substation is greater than or equal to 4, the 3 largest infeeds are ignored.

Under a variety of operating conditions, the relay will over-reach or under-reach and may lead to mal-operation. This strategy uses the actual throttling factor for the setting of the relay to enable the relay to be more attuned to current power system conditions. Consider the setting of the relay on Legacy to Deeside Feeder at the Legacy Busbar illustrated in Fig.5.1. Mal-operation of the zone 3 element of the distance relay for a 3 phase fault applied to the Pentir 400 kV Busbar for both the actual NGC setting, Fig.5.9.a, and the adaptive setting determined in direct accordance with the NGC strategy, Fig.5.9.b occurs. However, using the actual throttling factor, the relay correctly operates, Fig.5.9.c (ie: point 6 is inside the characteristic circle).

5.4.2.2 The Setting of Protection Relays Constrained By Actual Load and Not Worst Case Load.

Whilst the relay on Legacy to Deeside Feeder at the Legacy Busbar using the adaptive setting with the actual throttling factor manages to clear the Pentir 400 kV busbar fault, and offer improved performance relative to the actual setting (setting 1) and the adapted setting in accordance with the strategy (setting 2), all three settings fail to clear faults at the Trawsfynydd 400 kV mesh corner and the Capenhurst 275 kV busbars. By not constraining the zone 3 setting by worst case load but by actual load, the relay coverage of faults is improved. In this instance, faults at the Trawsfynydd mesh-corner and the Capenhurst 275 kV busbars remains undetected. As such, although the performance is improved, it is not perfect.

5.4.2.3 Optimising Protection Reliability

Setting protection relays in accordance with actual load and not worst case load increases the probability of incorrect relay operation, the final setting being a compromise between the requirements of dependability and security, the required level being obtained by further checks similar to those of ensuring correct operation of the zone 2 element on transformer feeders. For example, consider the system of Fig.5.10. The zone 3 element of the relay protecting transmission line AB at busbar A is ideally required to clear faults at busbars

C and E. Operating conditions can arise in which the measured impedance for a fault at busbar D will cause the relay to incorrectly operate. The adaptive algorithm is then faced with the dilemma:

- If the setting is reduced, it cannot be guaranteed that the zone 3 element will clear faults at busbars C and E.
- If the setting ensures that the zone 3 element will clear faults at busbars C and E, then the relay will operate incorrectly for faults at busbar D.

This leads to the concepts of protection dependability and security, the concepts of which have already been outlined in section 4.2.2. The traditional mechanisms of achieving preset levels of dependability and security have been outlined in section 4.3.1.8. However, by adaptively changing the setting the ratio of security to dependability can also be varied. This forms the basis for the remaining setting strategies (settings 5 to 12). Using these strategies the protection can be configured to:

- maximise dependability (ie: Settings 5 and 9).
- maximise security (ie: Settings 6 and 10).
- minimise the total number of mal-operations including both incorrect operations and failures to operate (ie: Settings 7, 8, 11 and 12).

Each of these settings may be constrained by the worst case loading or constrained by the actual loading. It should be noted that in minimising the total number of mal-operations, scenarios arise in which a range of settings have the same performance. To overcome this, the setting is biased to either dependability or security.

This move away from the conventional setting strategy approach has a significant impact on the performance of the protection system. As shown in Fig.5.7.c, the total number of mal-operations can be reduced from 78 in the case of the actual NGC setting to 29 by minimising the number of mal-operations. Importantly, the protection system can be configured dependent on the system operators requirements for security and dependability.

5.5 Limitations of Protection Relay Adaptation

5.5.1 Introduction

Whilst it is desirable to attain 100% performance of the protection system, the practical and economic issues of attaining this make it impossible. With the distance relay, some of the fundamental principles on which the relay design itself are based make this impossible to achieve. Three limitations are discussed below.

5.5.2 The Setting of Relays with Measured Impedances in Negative Quadrants of the Impedance Plane.

In highly inter-connected networks, operating scenarios arise, Fig.5.11, in which the measured impedance by the relay for a fault out of the next substation to the protected feeder will appear in the negative quadrants of the impedance plane and fail to initiate the protection. This results from the influence of the remote end throttling, T ($=I_B/I_A$). To ensure correct operation of distance relays in adaptive schemes the criterion for the reverse reach needs alteration together with the ability to change the characteristic type and shape. As such, this shows a limitation of the current system. This is illustrated by considering the measured impedance, Fig.5.9, seen by the distance relay on the Legacy to Deeside Feeder at the Legacy busbar for a fault on the Trawsfynydd 400 kV mesh corner of Fig.5.1. To ensure correct operation of distance relays in adaptive schemes the criterion for the reverse reach needs to be changed together with the ability to change the characteristic type.

5.5.3 Adaptive Setting of Protection Relays in Accordance with Actual Load and Not Worst Case Load

When adaptively changing relays in accordance with actual load and not worst case load, careful consideration should be given to the performance of the relays under operational contingencies. For example, it is well known that under pre-fault operating conditions, an increase in load current corresponds to a decrease in measured impedance (see chapter 4). Thus, should a scenario arise in which load current is suddenly transferred to the adaptively protected feeder constrained by actual load and not worst case load, the relay could mal-operate before its setting has been updated to reflect the new system loading.

5.5.4 The Setting of Distance Relays Protecting Transformer Feeders

The zone 1 and 2 settings of a distance relay protecting a transformer feeder, determined in accordance with the NGC setting strategy, are defined by the relations [5.3]:

$$Z_{zone1} = 80\%.Z_{ll} + 50\%.Z_{tl} \qquad \textbf{(5.7)}$$

$$Z_{zone2} = 150\%.Z_{ll} + 125\%.Z_{tl} \qquad \textbf{(5.8)}$$

In cases where transformer feeders are connected to downstream transmission lines the zone 2 invariably over-reaches, the determined setting often detecting faults at the remote busbar out of the next substation and hence operates incorrectly. This becomes particularly important in the adaptive setting of relays. To ensure coordination and avoid over-reach mal-operation of relays protecting transformer feeders it is necessary to significantly reduce the zone 2 setting whilst ensuring that faults at the remote busbar of the protected feeder are cleared.

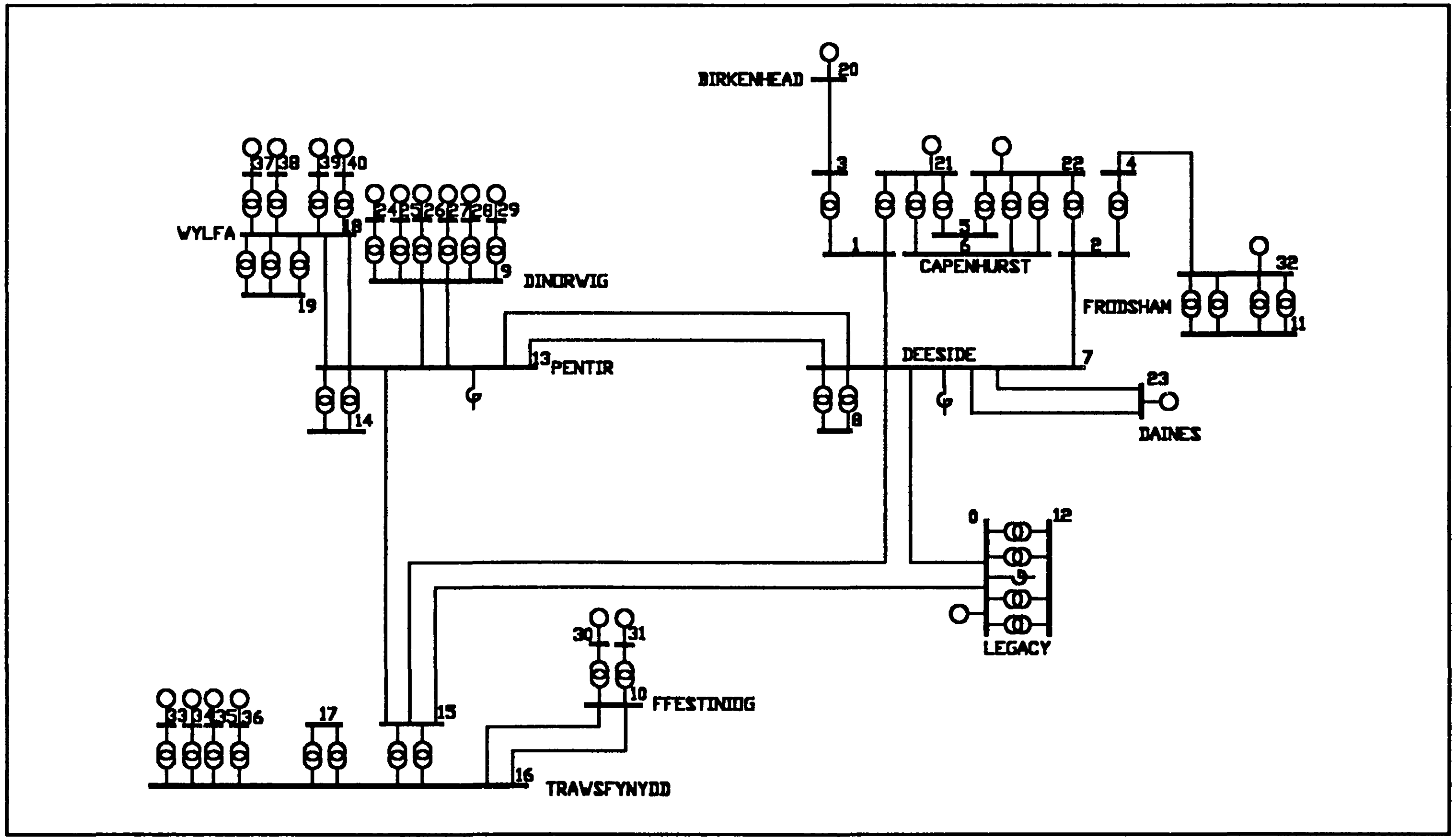

Figure 5.1 The North Wales 400 / 275 kV Network

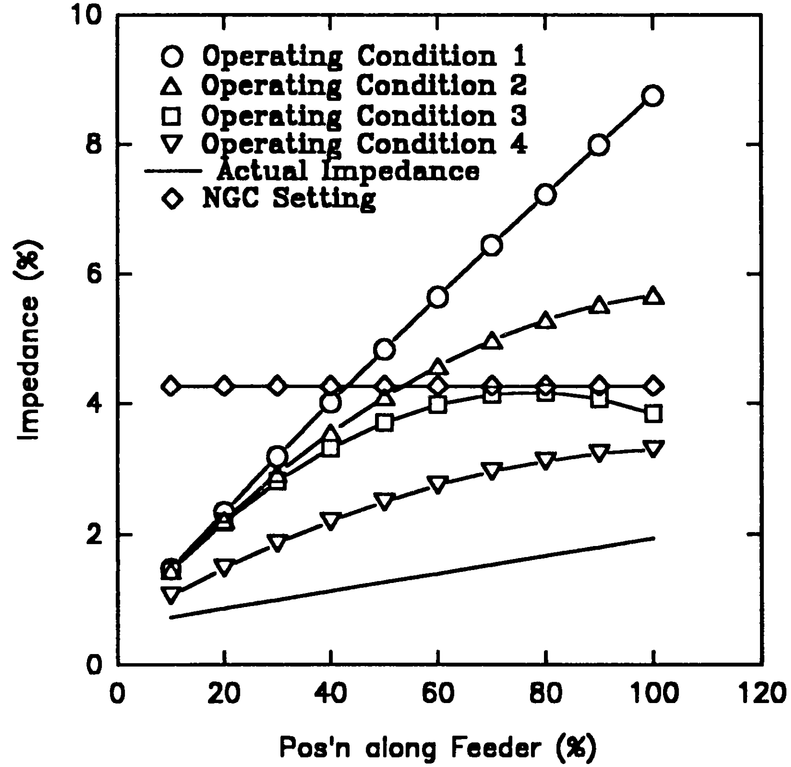

Figure 5.2 The Measured Impedance By a Distance Relay on the Wylfa to Pentir Feeder at the Wylfa Bus for 3 Phase Faults along the Pentir to Deeside Feeder

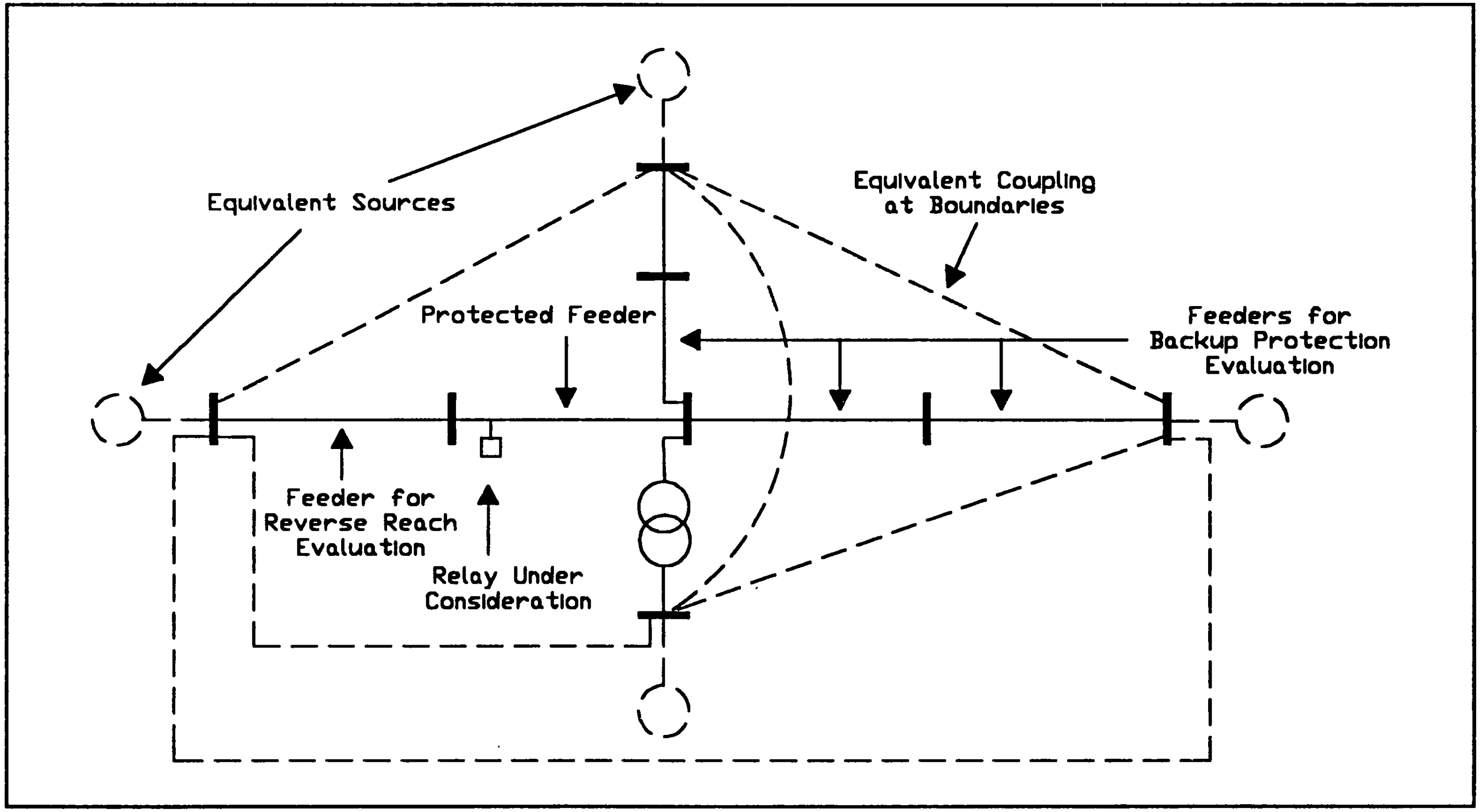

Figure 5.3 The Reduced Impedance Model

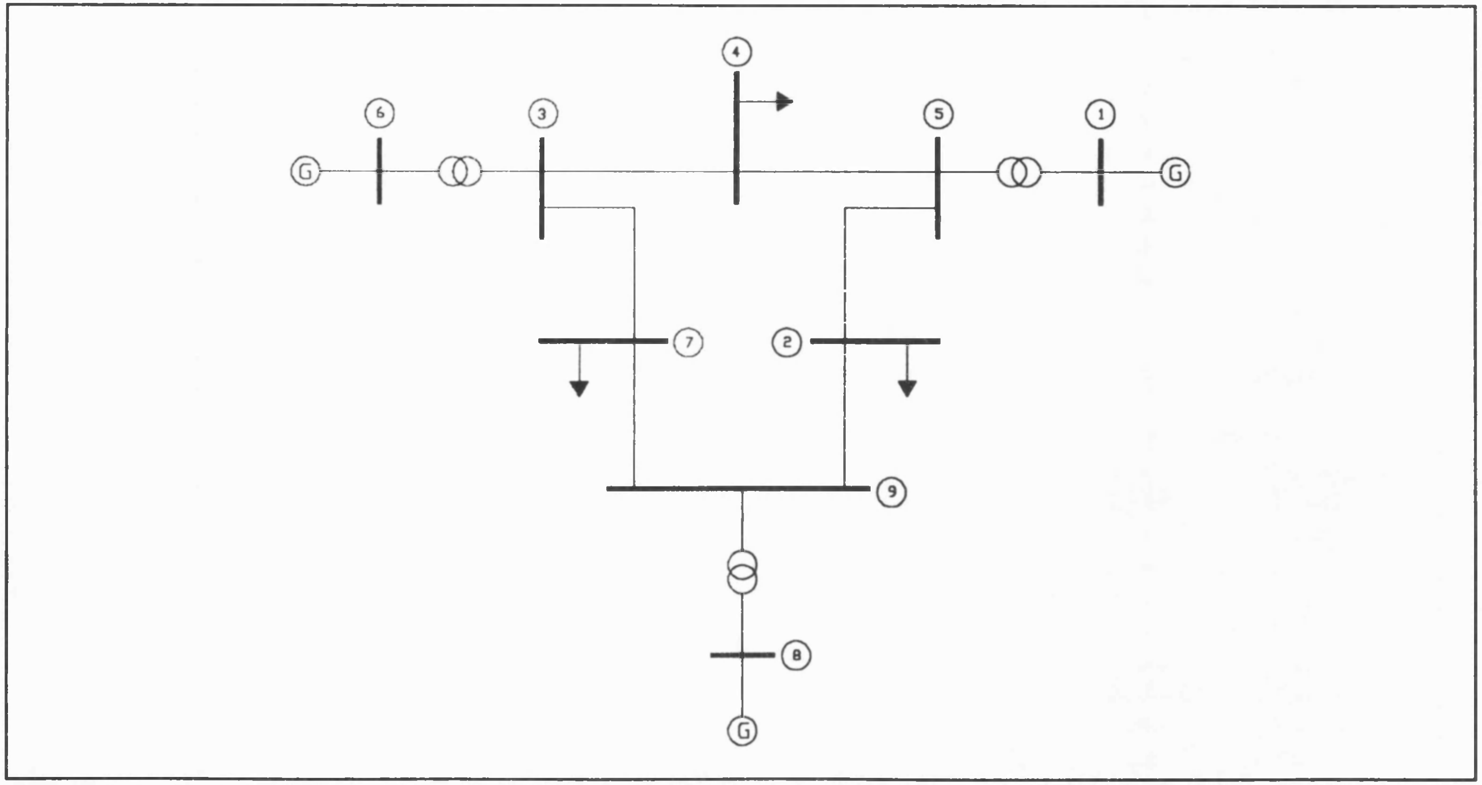

Figure 5.4 Simple Network for Illustrating the Formulation of the Reduced Impedance Model

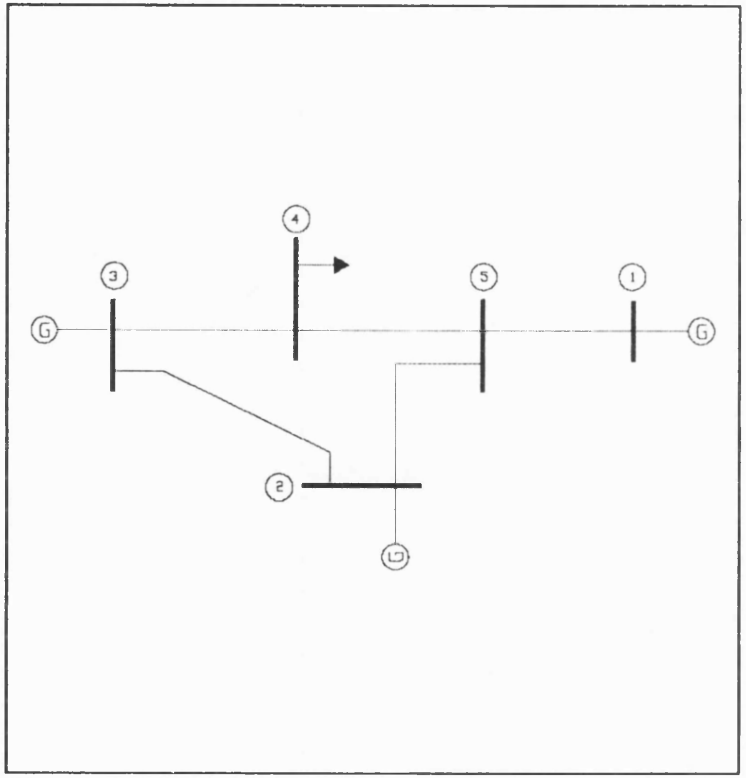

Figure 5.5 The Reduced Network for the Operating Scenario where all Circuit Breakers are Closed

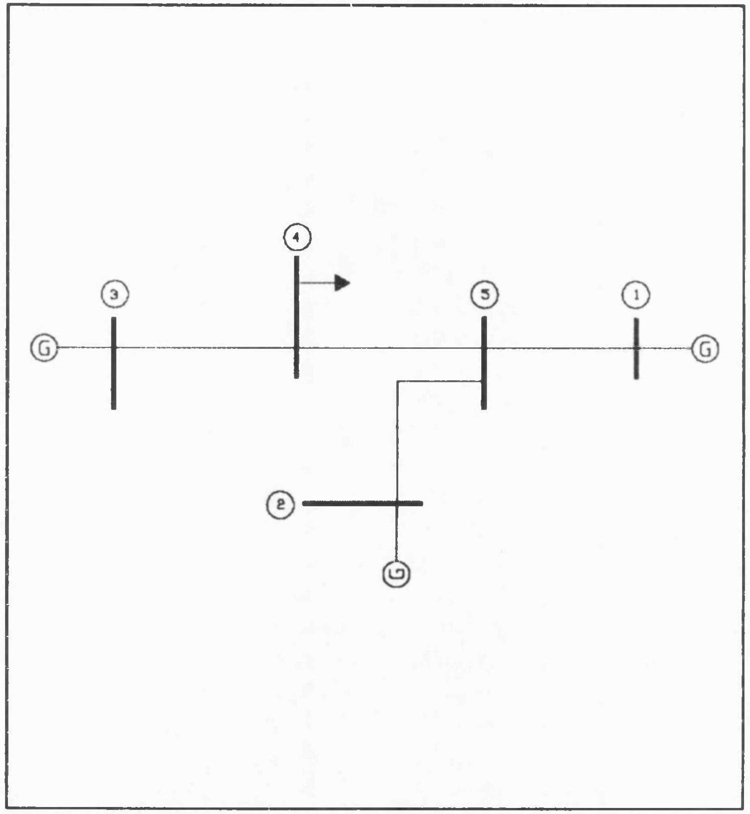

Figure 5.6 The Influence of Changes in Topology on the Reduced Model

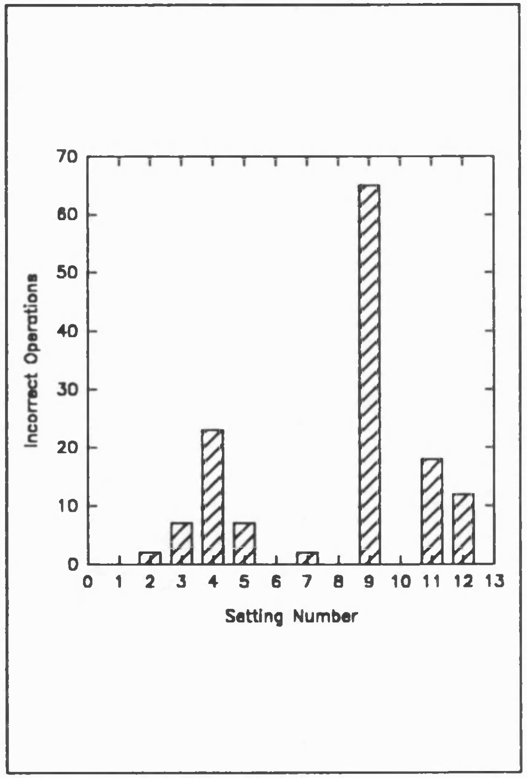

Figure 5.7.a The Relative Performance of the Individual Settings Classified in Terms of Incorrect Operations

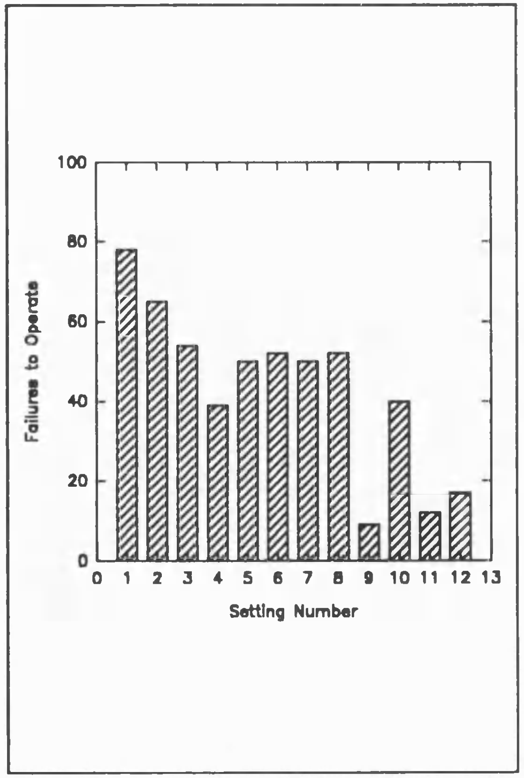

Figure 5.7.b The Relative Performance of the Individual Settings Classified in Terms of Failures to Operate

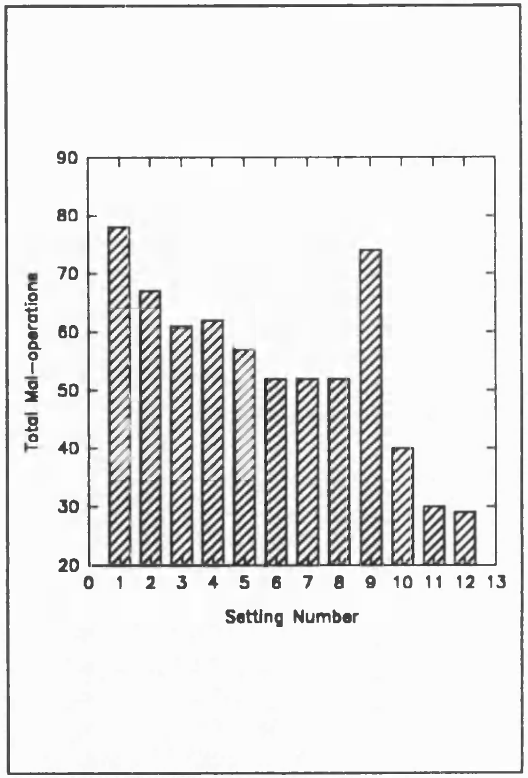

Figure 5.7.c The Relative Performance of the Individual Settings Classified in Terms of the Total Mal-operations

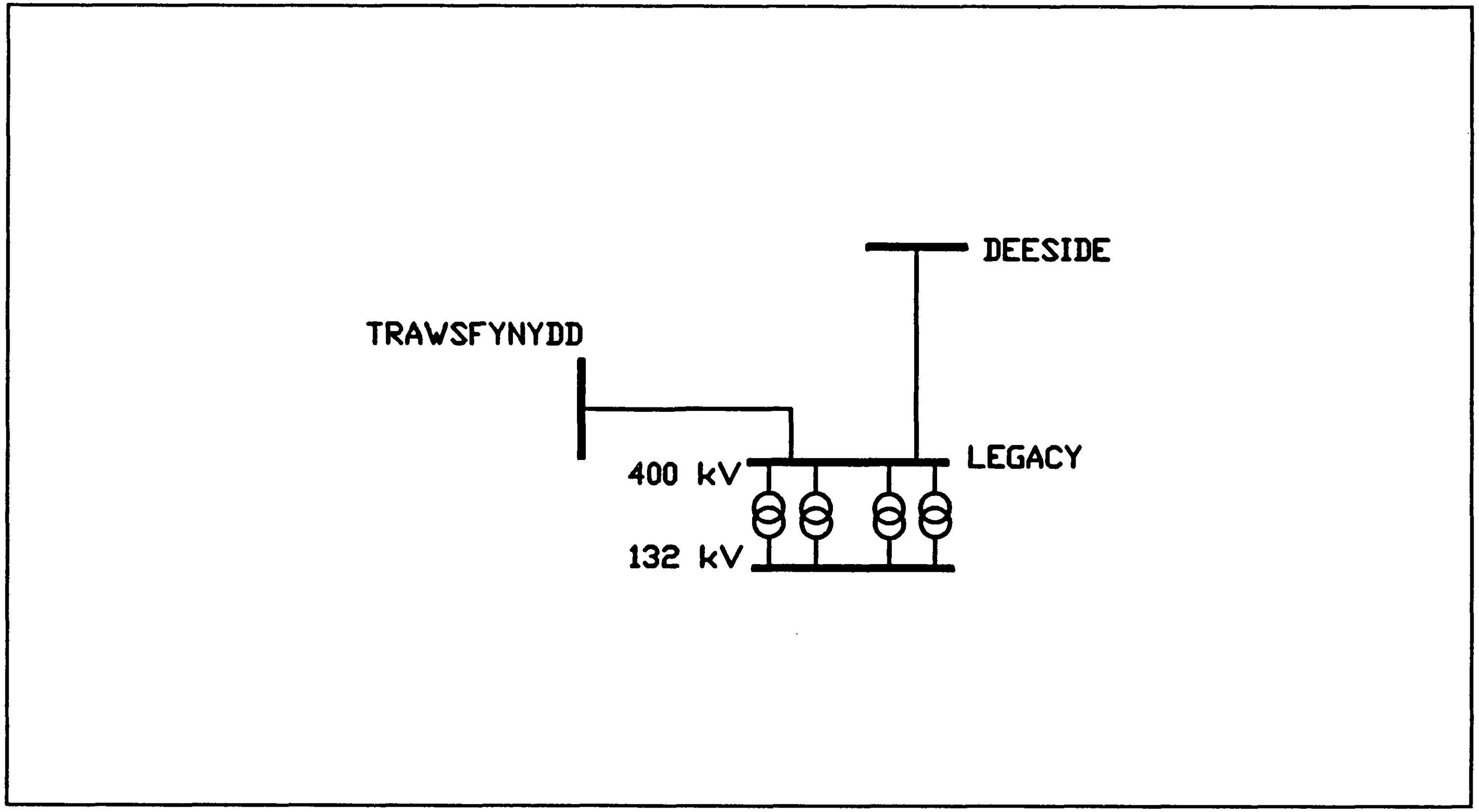

Figure 5.8 Simplified Network around Legacy

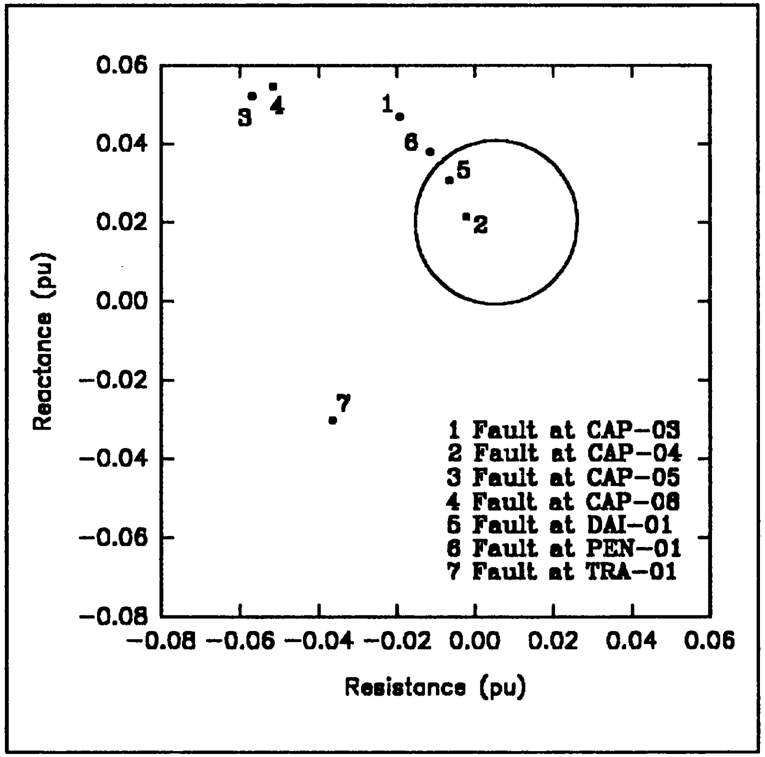

Figure 5.9.a The Performance of the Zone 3 Element (represented by circle) of a Relay on the Legacy to Deeside Feeder at the Legacy Bus Using Setting 1

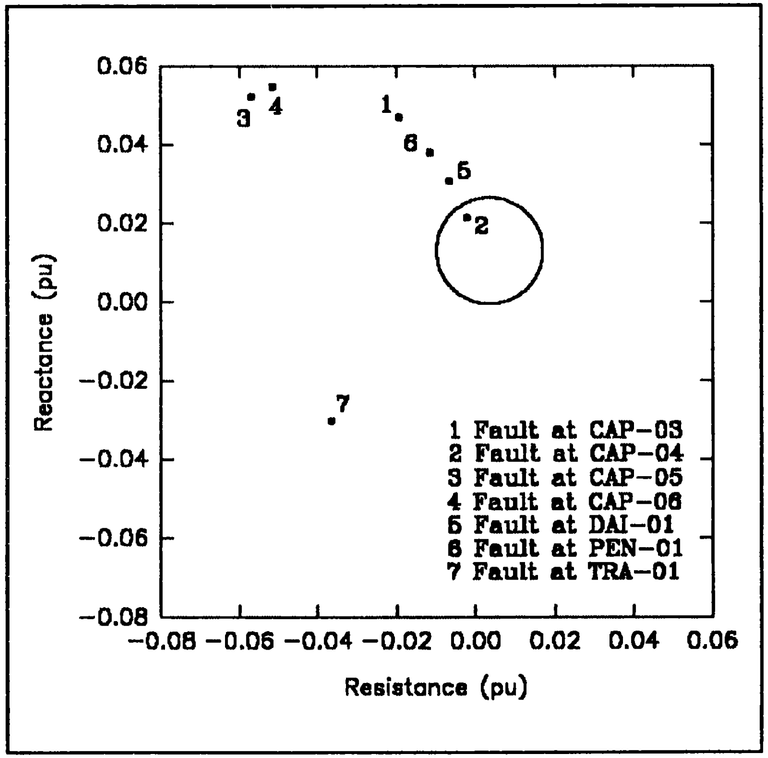

Figure 5.9.b The Performance of the Zone 3 Element (represented by circle) of a Relay on the Legacy to Deeside Feeder at the Legacy Bus Using Setting 2

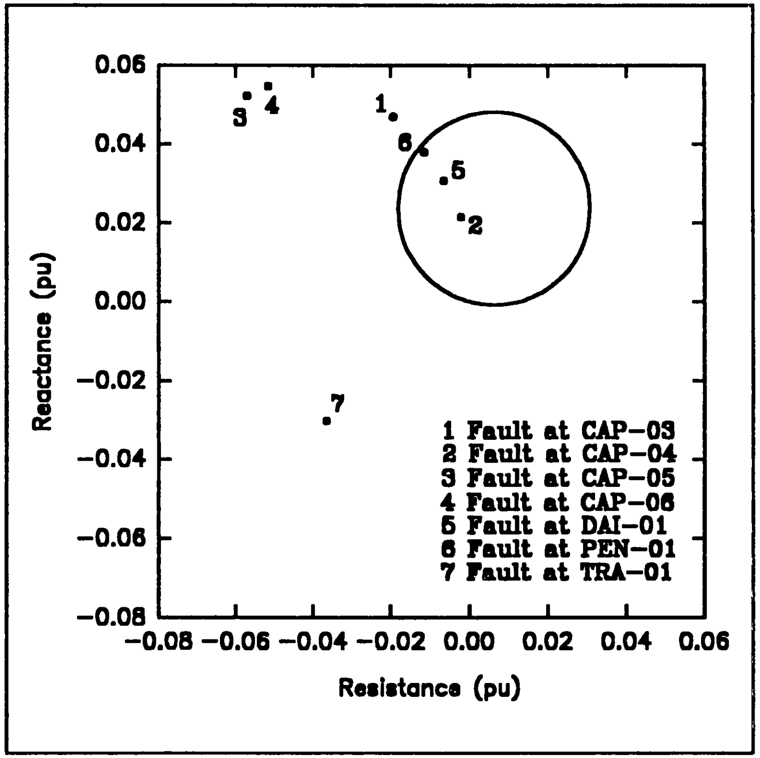

Figure 5.9.c The Performance of the Zone 3 Element (represented by circle) of a Relay on the Legacy to Deeside Feeder at the Legacy Bus Using Setting 3

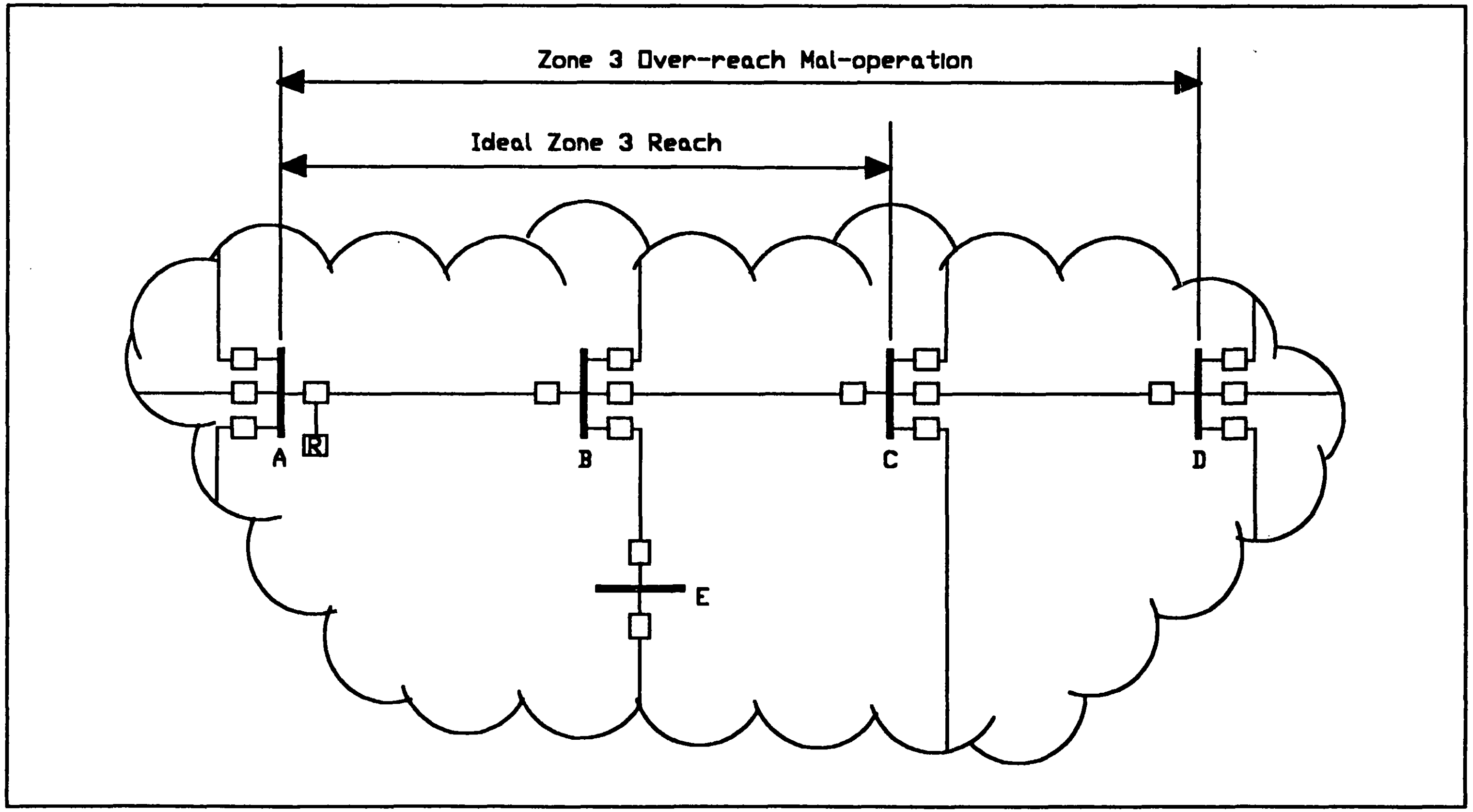

Figure 5.10 Adaptive Relay Setting by Reliability Optimisation

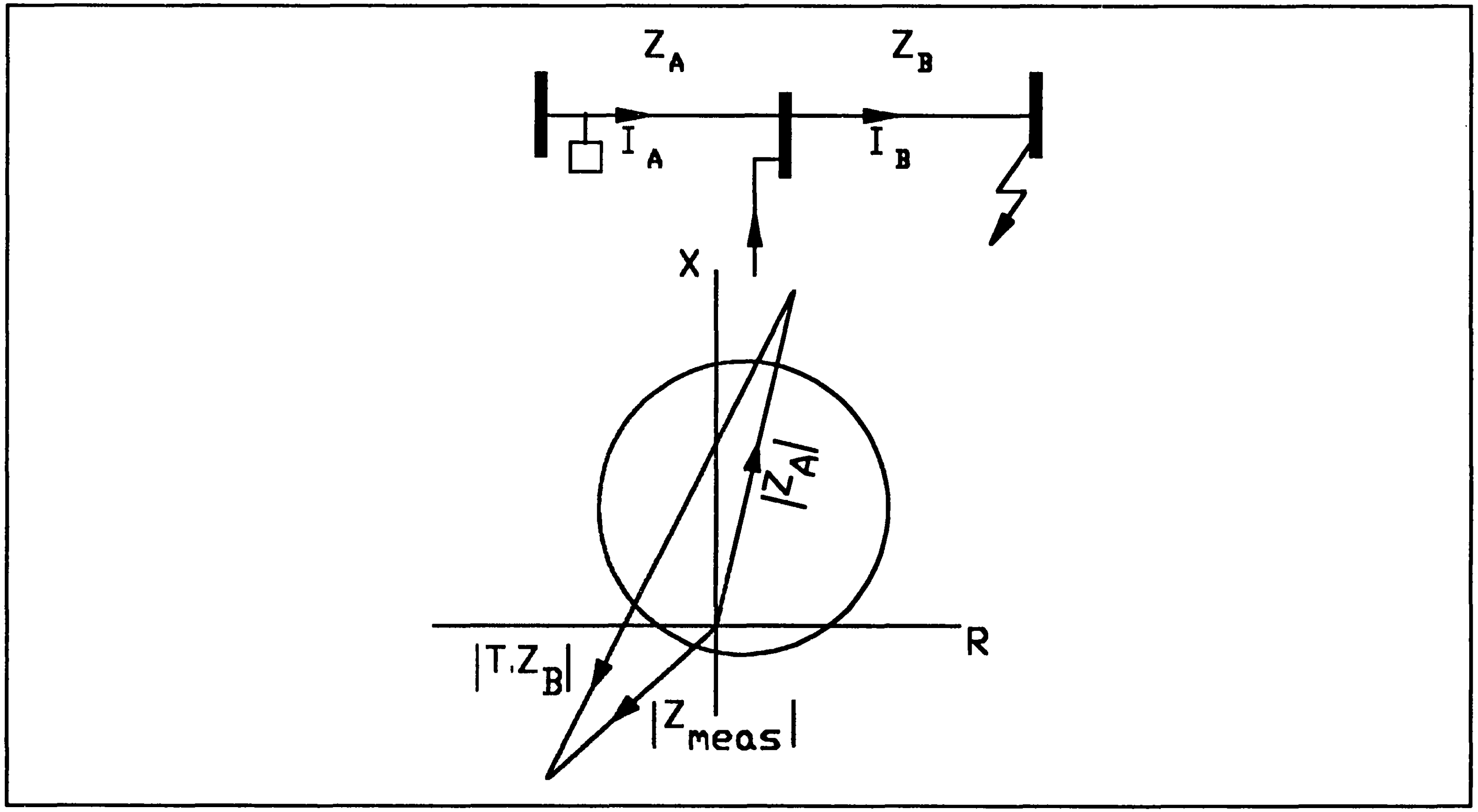

Figure 5.11 Limitation of Adaptive Relay Setting in Negative Quadrants

CHAPTER 6

OPTIMISATION OF DISTANCE RELAY PERFORMANCE UNDER HIGH RESISTANCE EARTH FAULTS WITHIN AN INTEGRATED DIGITAL HIERARCHICAL CONTROL AND PROTECTION SYSTEM

6.1 Introduction

Adaptive protection systems optimise the performance of relays by adapting their functionality via two principle means: the setting and the characteristic. The previous chapter concentrated on the first of these, the adaptive setting of distance relays. Whilst setting adaptation is important in the optimisation of the performance of the distance relay, advantanges can only be gained where remote end infeed is influenced. This only enables optimisation of:

- backup functions of distance relays.
- distance relays protecting teed feeders.

The second method, characteristic adaptation compliments setting adaptation and enables further improvements in the performance of the distance relay. Importantly, it enables optimisation of the primary function of the relay. As such, characteristic adaptation forms an important and integral part of relay adaptation.

The relay characteristic has traditionally been chosen by the protection engineer based on certain assumptions about the system operating conditions. In analogue and electro-mechanical relays, the choice of characteristic shapes available has been governed by issues of implementation. This is not the case for digital relays in which it is feasible to arbitrarily specify the trip region, eg: the quadrilateral relay. As one of the most common types of fault occurring on power systems is the single phase to earth fault, a method of adaptively changing the characteristic for this scenario will be outlined. The fault path to earth often contains resistance, the magnitude of which varies considerably depending on the cause. For single phase to earth faults resulting from the flashover of the over head transmission line insulators such that the conductor is short circuited to ground via the tower, the fault resistances may be as high as 10 ohms [6.1]. However, often towers are fitted with ground wires such that the fault resistance seldom exceeds 3 ohms. This is not the case for faults caused by contact between vegetation and a conductor; or a broken conductor. Here the fault resistance is very high.

The impedance measured by distance relays is adversely effected by the fault path resistance. With reference to the one line diagram of Fig.6.1, for an a-phase to earth fault occurring at F through a fault resistance R_f, the complex measured impedance, $Z_{measured}$, by a relay at M is given by:

$$Z_{measured} = \alpha . Z_{1l} + \frac{I_{mf} + I_{nf}}{I_{mf}} R_f \tag{6.1}$$

Thus, in contrast to solid faults, resistive faults make the measured impedance at the relaying point a function of the current contribution, I_{nf}, from the remote end. This current contribution, or remote end infeed, is dependent not only on the fault position and fault resistance, but also the pre-fault power system operating conditions. To determine the influence of these effects, it is necessary to derive expressions that relate the power system conditions to the measured impedance seen by the distance relay.

For an a-phase to earth fault on the system of Fig.6.1 the corresponding residually compensated element of the relay will measure an apparent impedance given by the expression [1.46]:

$$Z_{measured} = \alpha . Z_{1l} + \frac{3 I_f R_f}{I_a + K_{res} I_{res}} \tag{6.2}$$

This may be written more succinctly as:

$$Z_{measured} = \alpha . Z_{1l} + Z_{rf} \tag{6.3}$$

where:

$$Z_{rf} = \frac{3.I_f.R_f}{I_a + K_{res}.I_{res}} \tag{6.4}$$

The quantity Z_{rf} is complex and as such has a magnitude and argument, Fig.6.2:

$$|Z_{rf}| = \left| \frac{3.I_f.R_f}{I_a + K_{res}.I_{res}} \right| \tag{6.5}$$

$$\theta = arg\left[\frac{3.I_f.R_f}{I_a + K_{res}.I_{res}} \right] \tag{6.6}$$

To evaluate the influence of the prevailing system conditions and earth fault resistance on measured impedance it is important to derive an expression in terms of these quantities. It is shown in Appendix B [6.2] that the measured impedance may be directly related to the fault position, fault resistance, source impedances and source voltages by the expression:

$$Z_{measured} = \alpha.Z_{l1} + \cfrac{3.R_f}{\cfrac{(Z_{\sum}+3.R_f).(E_{m1}-E_{n1})}{(Z_{sn1}+(1-\alpha).Z_{l1}).E_{m1}+(Z_{sm1}+\alpha.Z_{l1}).E_{n1})}+2.c_1+c_0.(1+3.K_{res})} \tag{6.7}$$

where:

$$Z_{\Sigma} = \frac{2.(Z_{sm1}+\alpha.Z_{l1}).(Z_{sn1}+(1-\alpha).Z_{l1})}{Z_{sm1}+Z_{l1}+Z_{sn1}} + \frac{(Z_{sm0}+\alpha.Z_{l0}).(Z_{sn0}+(1-\alpha).Z_{l0})}{Z_{sm0}+Z_{l0}+Z_{sn0}} \qquad (6.8)$$

To enable analysis, a 400 kV, 100 km double end fed transmission line with parameters shown in Appendix C have been used. For the operating conditions shown in Appendix D, the influences of all parameters on the measured impedance as fault resistance is varied, are illustrated in Fig.6.3 to Fig.6.13. The last diagram is of particular interest as the area formed by the bounding set of measured impedances in Fig.6.13 illustrates the ideal characteristic shape to ensure correct clearance of faults with R_f up to the maximum defined in the operating conditions. The ideal characteristic shape varies depending upon the prevailing operating conditions. For the two different sets of operating conditions shown in Appendix E and Appendix F, the measured impedance, for single phase to earth faults for varying fault location (0 to 80%) and R_f is pictorially illustrated in Fig.6.14. The operating conditions in Appendix E relate to a pre-fault load flow from N to M. The operating conditions in Appendix F correspond to a pre-fault load flow from M to N. By superimposing the conventional mho relay and the quadrilateral relay it is shown in Fig.6.15 that the performance when subjected to high resistance earth faults is less than optimal. For faults at the zone 1 reach-point, the quadrilateral characteristic is prone to under-reaching for the conditions of importing load (Appendix E). Conversely, for the operating conditions of exporting load (Appendix F), the relay over-reaches. The circular nature of the mho relay ensures improved performance under conditions of exporting load (Appendix F) at the expense of reduced performance under conditions of importing load (Appendix E). However, if the zone 1 characteristic were to be adapted to reflect current operating conditions, the performance could be optimised.

In order to ensure correct operation of the relay under these conditions, it is necessary to change the characteristic or setting of the relay. For the zone 1 element of the distance relay, little can be achieved by changing the setting as the safety margin utilised by the utility is largely in place to avoid incorrect operations occurring due to component tolerances. However, by adapting the characteristic it is possible to ensure correct operation. The ideal characteristic may be approximated by a quadrilateral characteristic in which the upper and lower reactance lines have been rotated by θ_1 and θ_2 as illustrated in Fig.6.16 about the solid fault reach point resistance line. The angles θ_1 and θ_2 are determined directly from equation (6.6) and correspond to the maximum fault resistance that can be accommodated at the reach-point and relaying point respectively, subject to the load and coordination constraints introduced in the previous section.

Using data available via the hierarchical structure and a reduced impedance model of the system at the relaying point in conjunction with an expert system having knowledge of the protection engineers requirements for the relay, a new characteristic may be determined.

6.2 System Description

The system developed is illustrated schematically in Fig.6.17, the functionality of each subsystem being briefly discussed.

6.2.1 The Impedance Model

Rockefeller et-al [6.4] introduced the benefits to be gained by providing distance relays with a simple impedance model of the system, located at the substation, whose parameters were continually updated by a central computing resource to enable optimisation of the performance of the relay using apriori information. In contrast to high speed channels required for carrier aided schemes, the performance of the protection is optimised by slowly varying parameters that occur due to demand fluctuations and circuit outages. The impedance model has the form depicted in Fig.6.1. The updated impedance model and associated data may then be used by the Fault Data Generator.

6.2.2 The Fault Data Generator

Using the impedance model, the fault data generator calculates the impedance, using the theory developed in Section 6.1, that the relay would measure for a number of fault scenarios encompassing the ideal trip region illustrated in Fig.6.14. Fault scenarios are generated over the following ranges:

- Fault Resistance: 0 to 300 Ω
- Fault Position: 0 to 80 %

This fault data is formulated in a manner for manipulation by the expert system enabling generation of the new characteristic.

6.2.3 The Expert System

The expert system comprises three main parts: the knowledge base, the inference engine and the interface, Fig.6.18:

- Knowledge Base: The knowledge base is a database that contains the information (facts) and rules (relationships) about a specific subject. This database holds the information received or discovered and incorporates functions for its management (addition, deletion, searching).
- Inference Engine: The inference engine is the method by which the computer, as opposed to the human, draws conclusions from the facts and relationships contained within the knowledge base.
- Interface: The interface is the method by which the expert system interacts

with the outside world.

Within the expert system, knowledge is represented using a frame based approach. The frame based method is derived from the simple semantic network method of knowledge representation in which knowledge is represented by a linear graph in which the nodes represent objects, events or situations and the arcs represent the relationship between nodes. For example to represent the statement that a *distance relay has a quadrilateral characteristic*, one could write:

$$\textit{distance relay} \xrightarrow{\textit{has a}} \textit{quadrilateral characteristic}$$

Frames are an extension of Semantic Networks in which the nodes are replaced by more structured groupings of information. This enables the object (nodes) to be related more easily to a number of attributes and their associated values and has the general form:

```
FRAME object
        {
        attribute 1     value 1
        attribute 2     value 2
        }
```

The expert system uses two main frames in its analysis, one defining the fault data and the other the lines within the characteristic each of which has been filled with illustrative data

```
FRAME fault_data
        {
        identifier          12
        resistance          30
        reactance           40
        position            80
        fault_resistance    5
        }

FRAME line
        {
        identifier          1
        gradient            0
        intercept           30
        status          ACTIVE
        }
```

The expert system, using a set of rules associated with each line making up the characteristic in conjunction with the new power system fault data defines the characteristic. The expert system interfaces to a number of support routines, the most commonly used being one to determine the angle, θ, of the fault resistance factor. The rules have the traditional structure:

IF <premise> THEN <action>

The expert system is required to have both forward and backward reasoning. On completion, the relay characteristic is updated as shown in Fig.6.16.

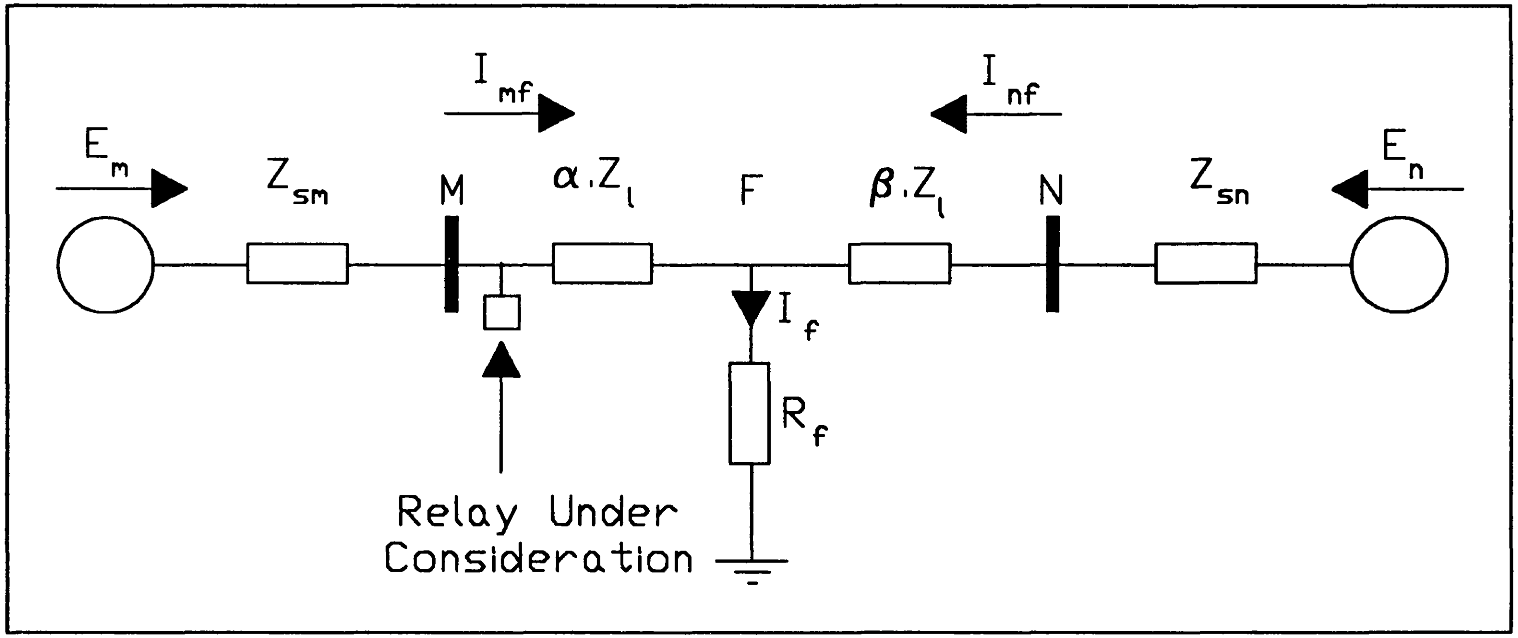

Figure 6.1 Double End Fed Transmission System with Resistive Earth Fault

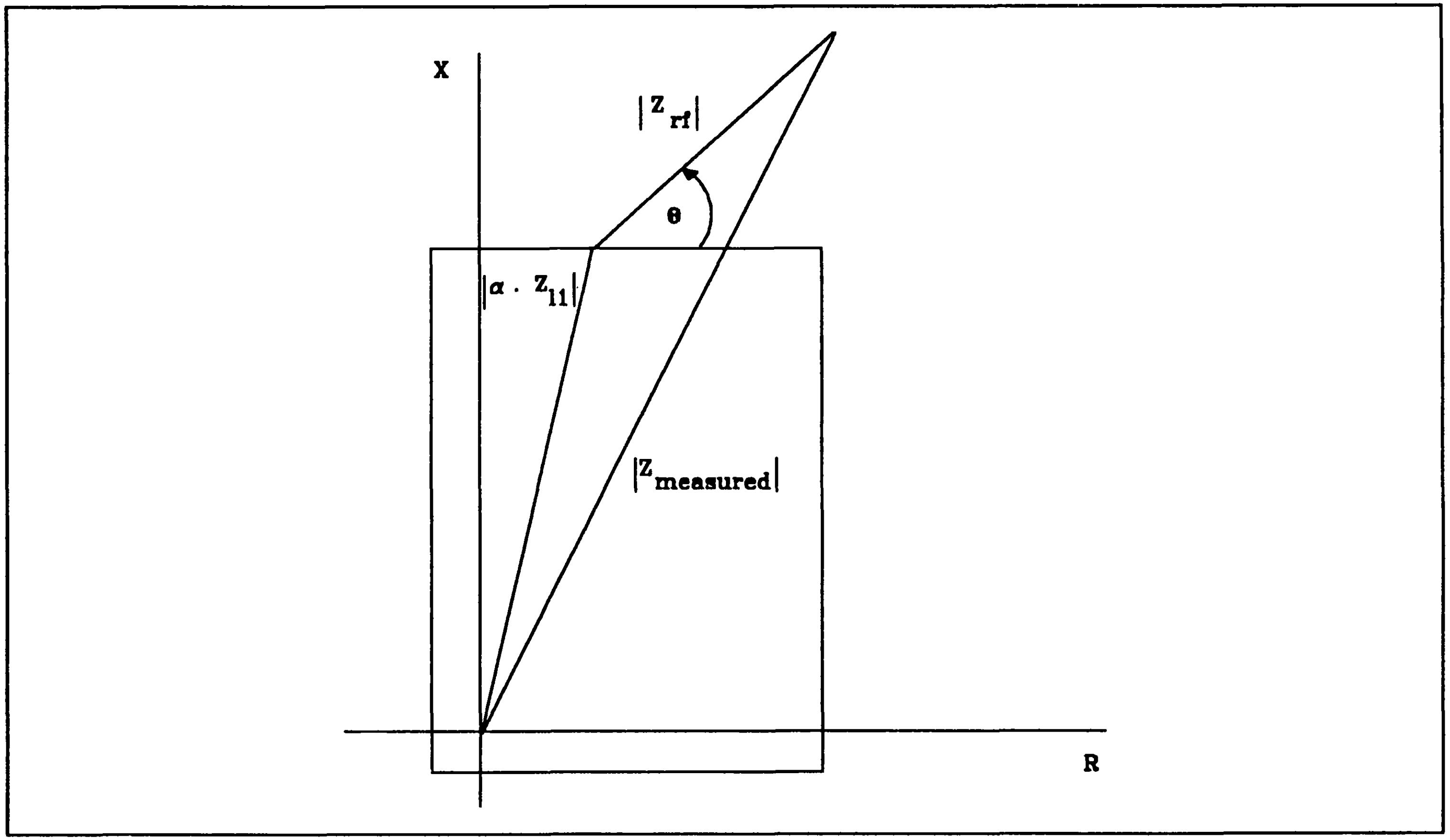

Figure 6.2 The Influence of Earth Fault Resistance on Measured Impedance

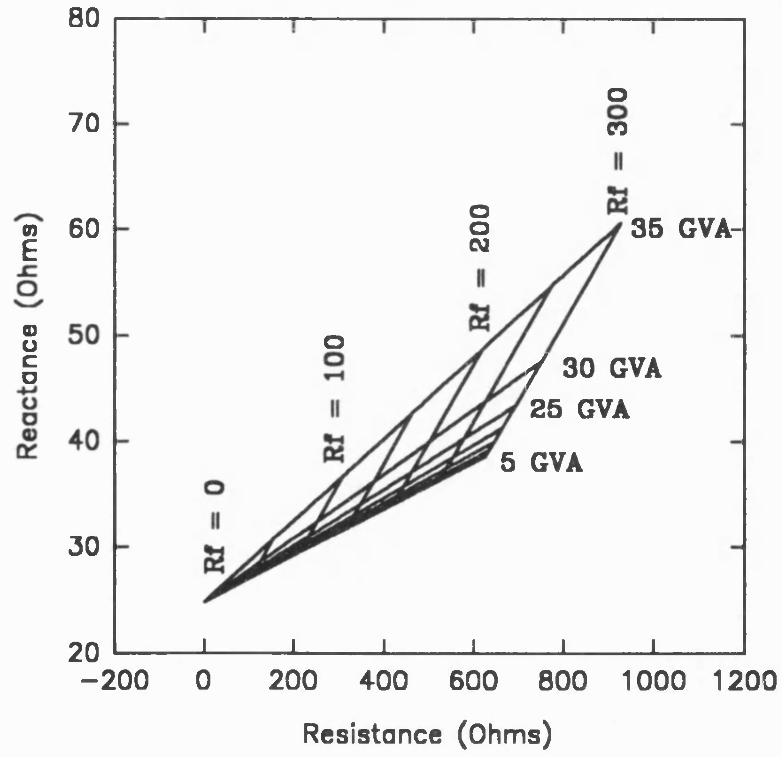

Figure 6.3 Influence of Variation of Source Capacity of M with Fault Resistance

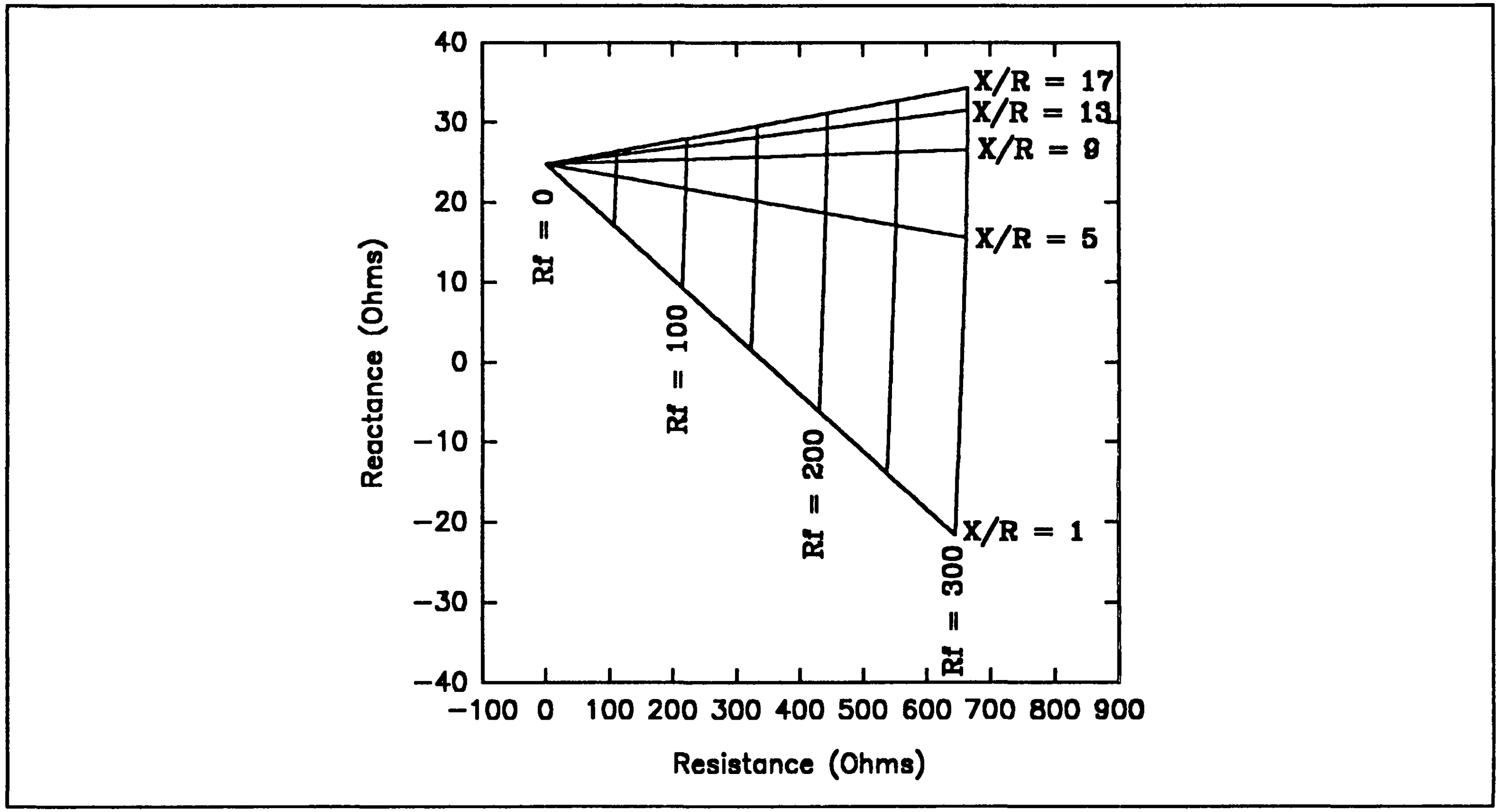

Figure 6.4 Influence of Variation of Source Reactance to Resistance Ratio of M with Fault Resistance

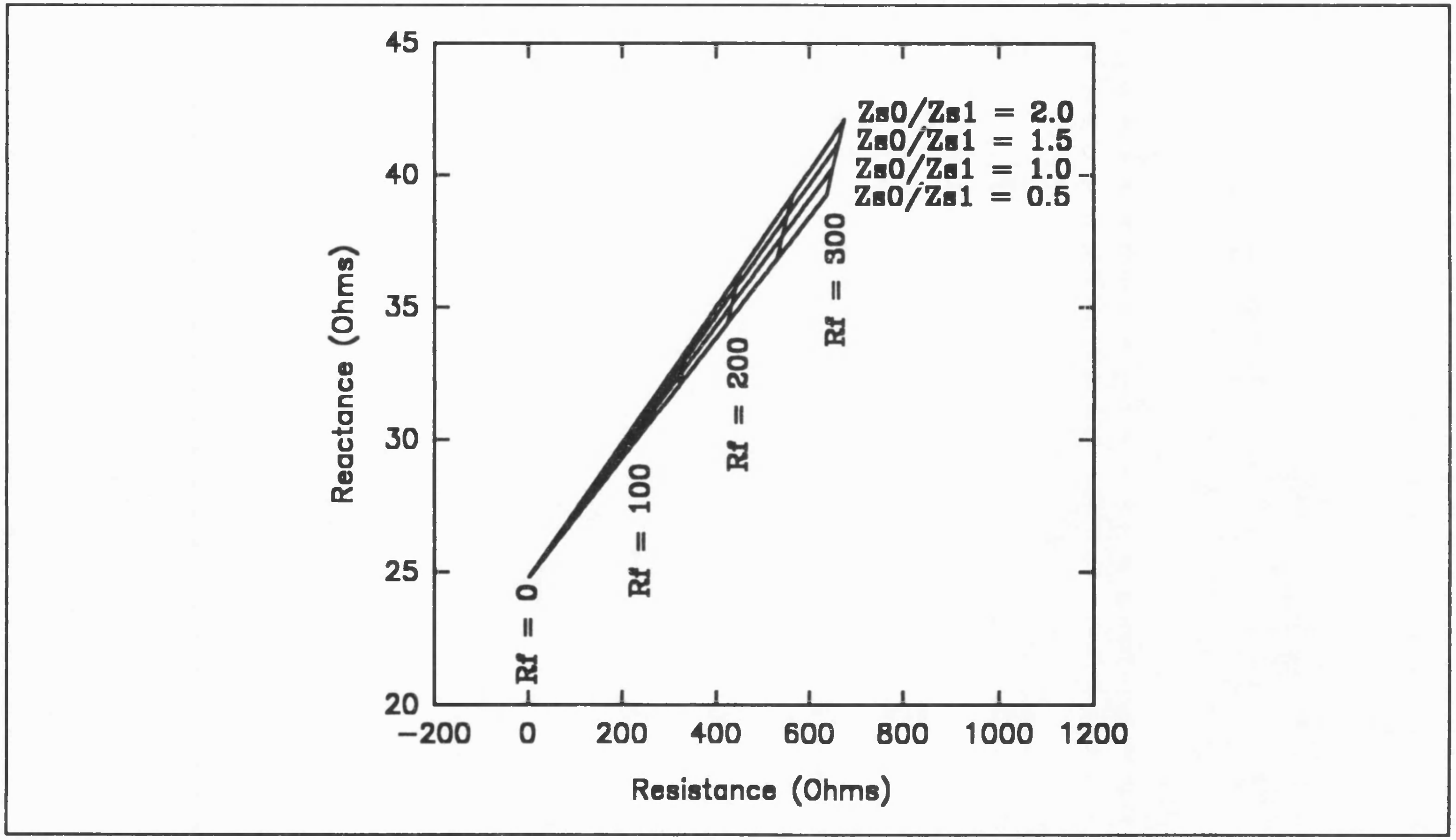

Figure 6.5 Influence of Variation of Source Ratio of Z_{s0} to Z_{s1} of M with Fault Resistance

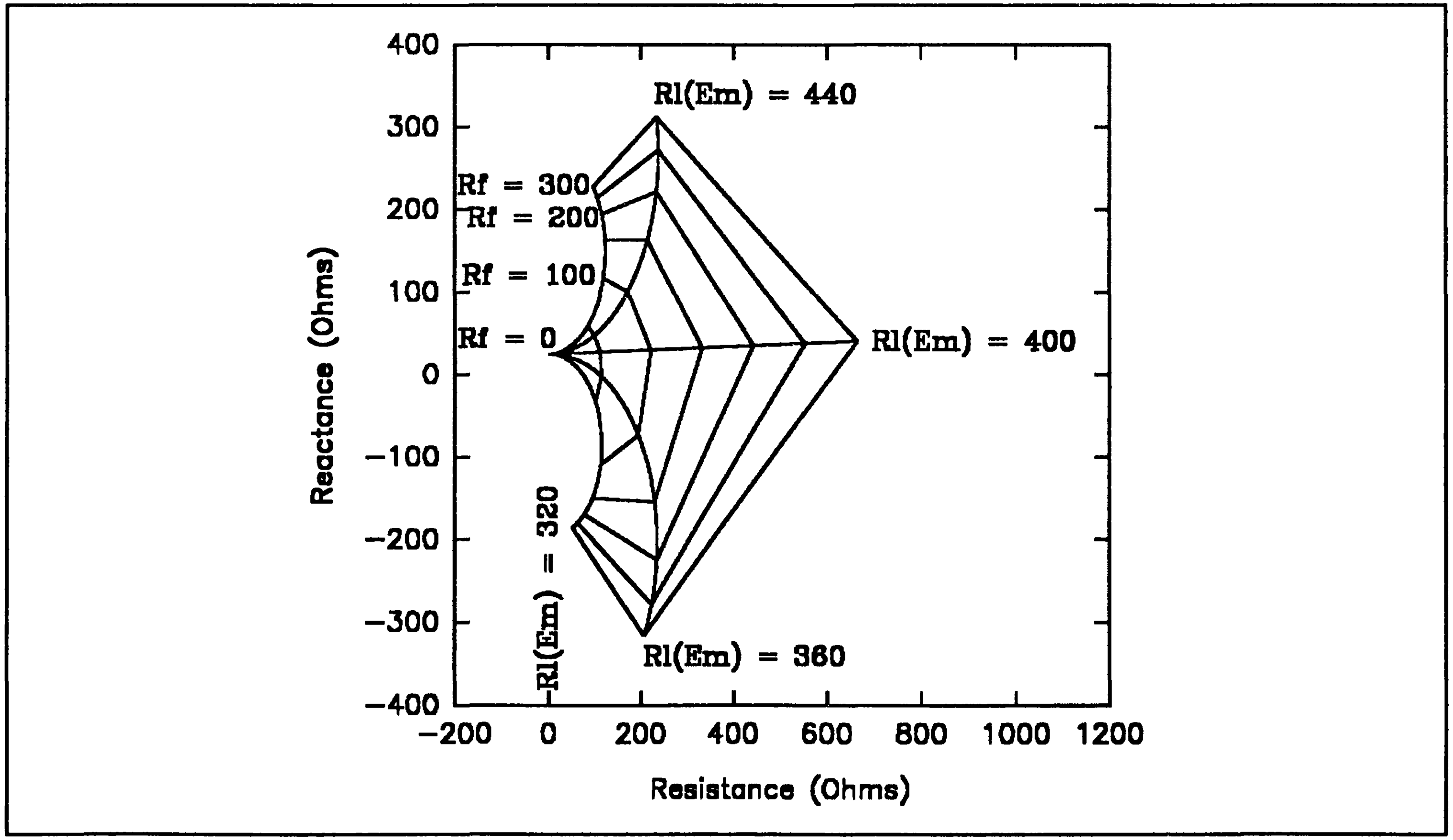

Figure 6.6 Influence of Variation of Real Voltage of Source M with Fault Resistance

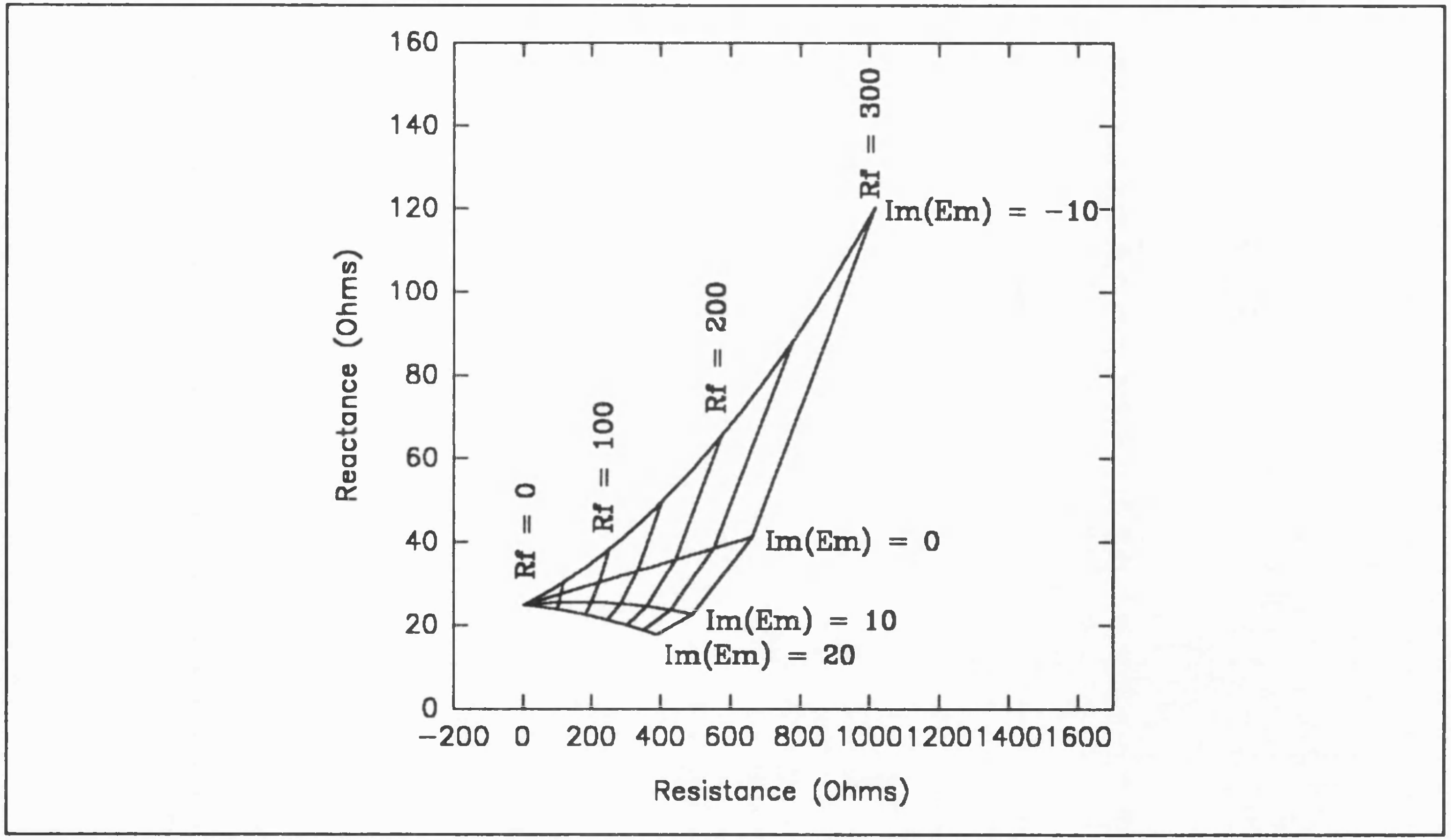

Figure 6.7 Influence of Variation of Reactive Voltage of Source M with Fault Resistance

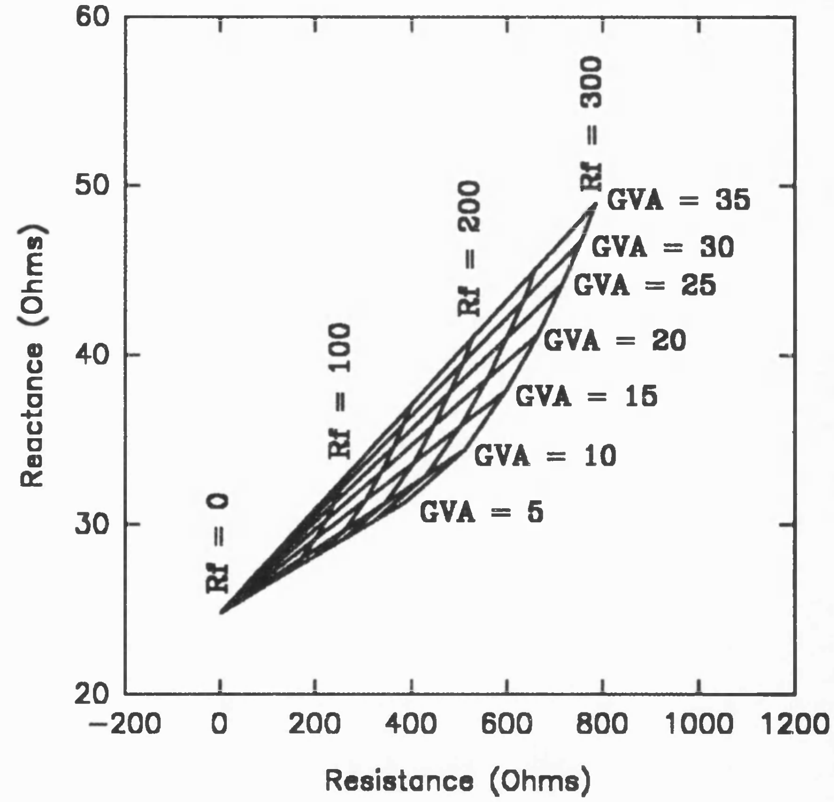

Figure 6.8 Influence of Variation of Source Capacity of N with Fault Resistance

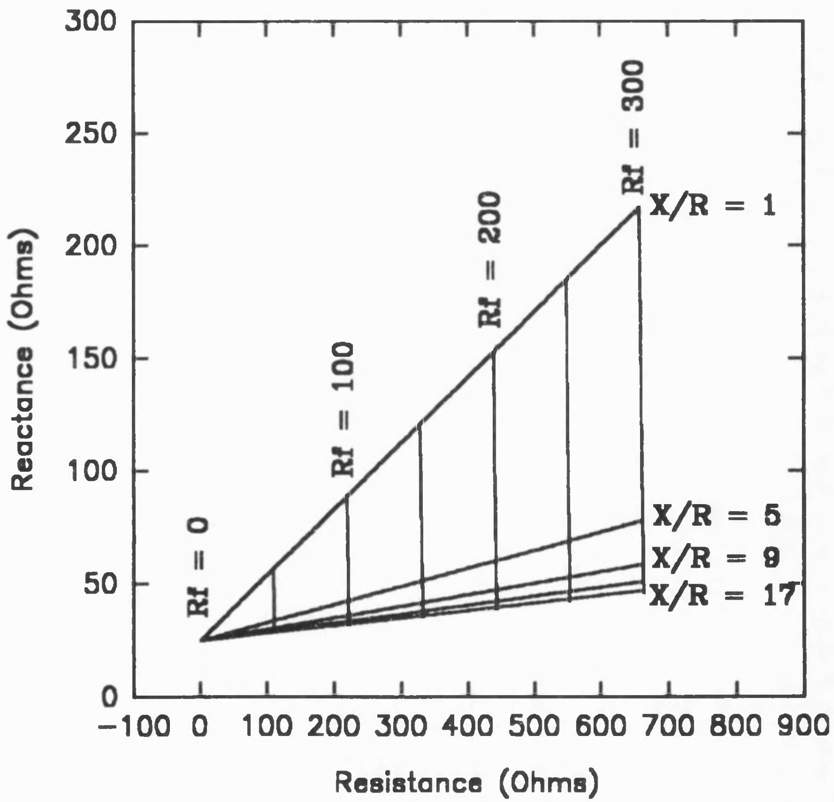

Figure 6.9 Influence of Variation of Source Reactance to Resistance Ratio of N with Fault Resistance

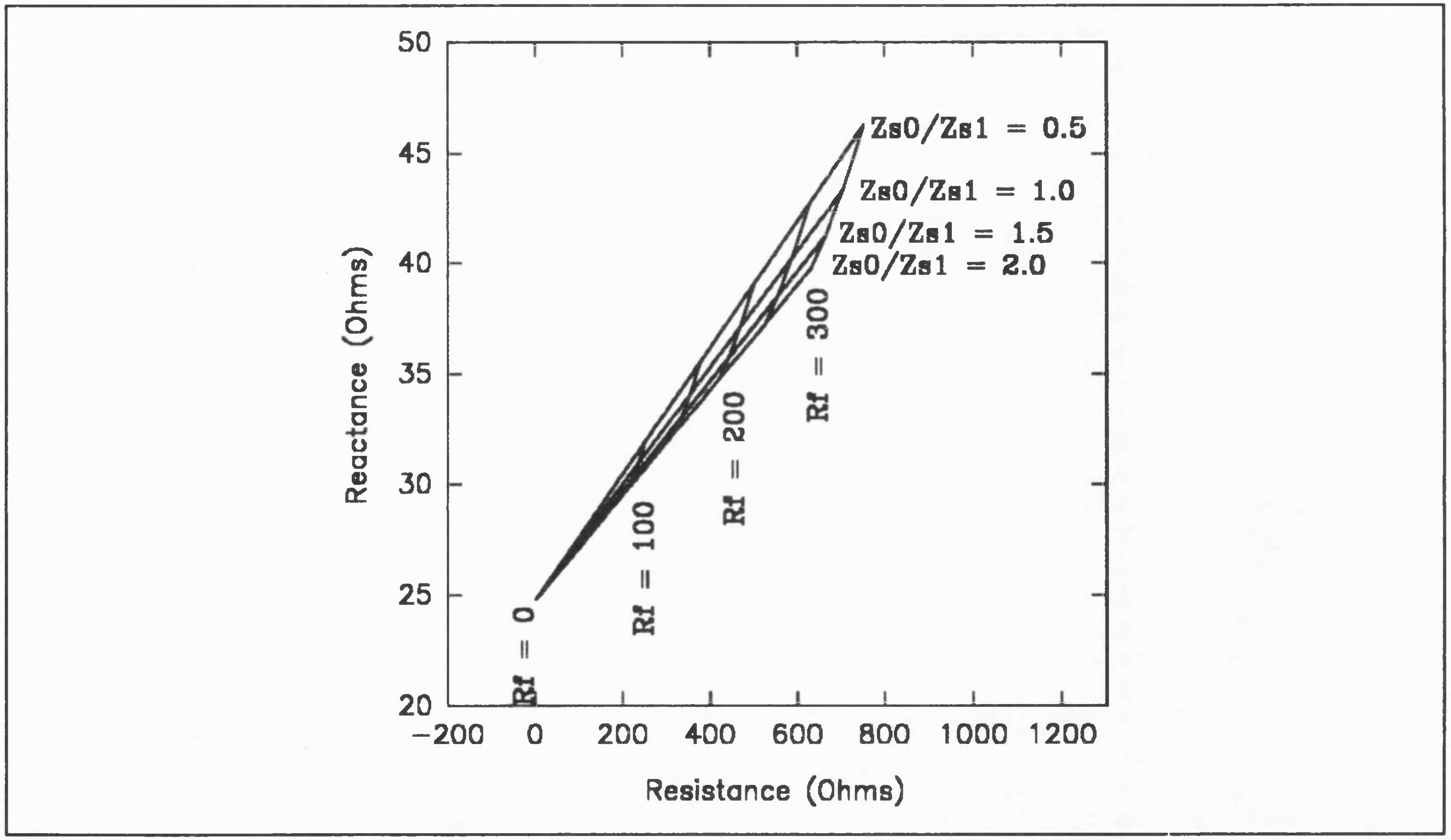

Figure 6.10 Influence of Variation of Source Z_{s0} to Z_{s1} Ratio of N with Fault Resistance

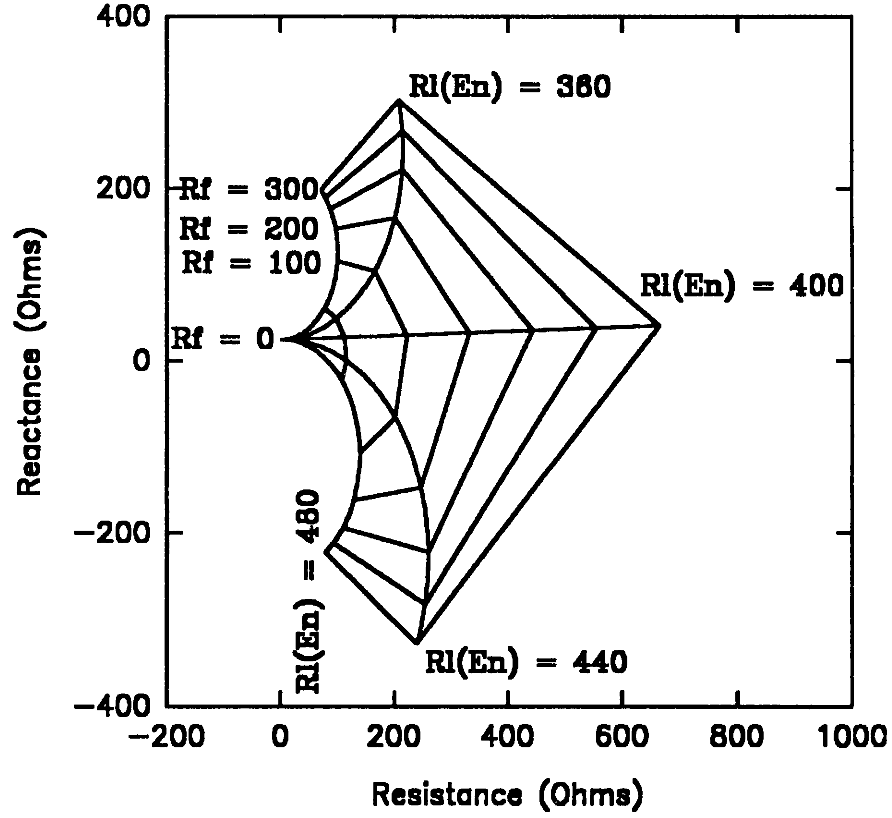

Figure 6.11 Influence of Variation of Real Voltage of Source N with Fault Resistance

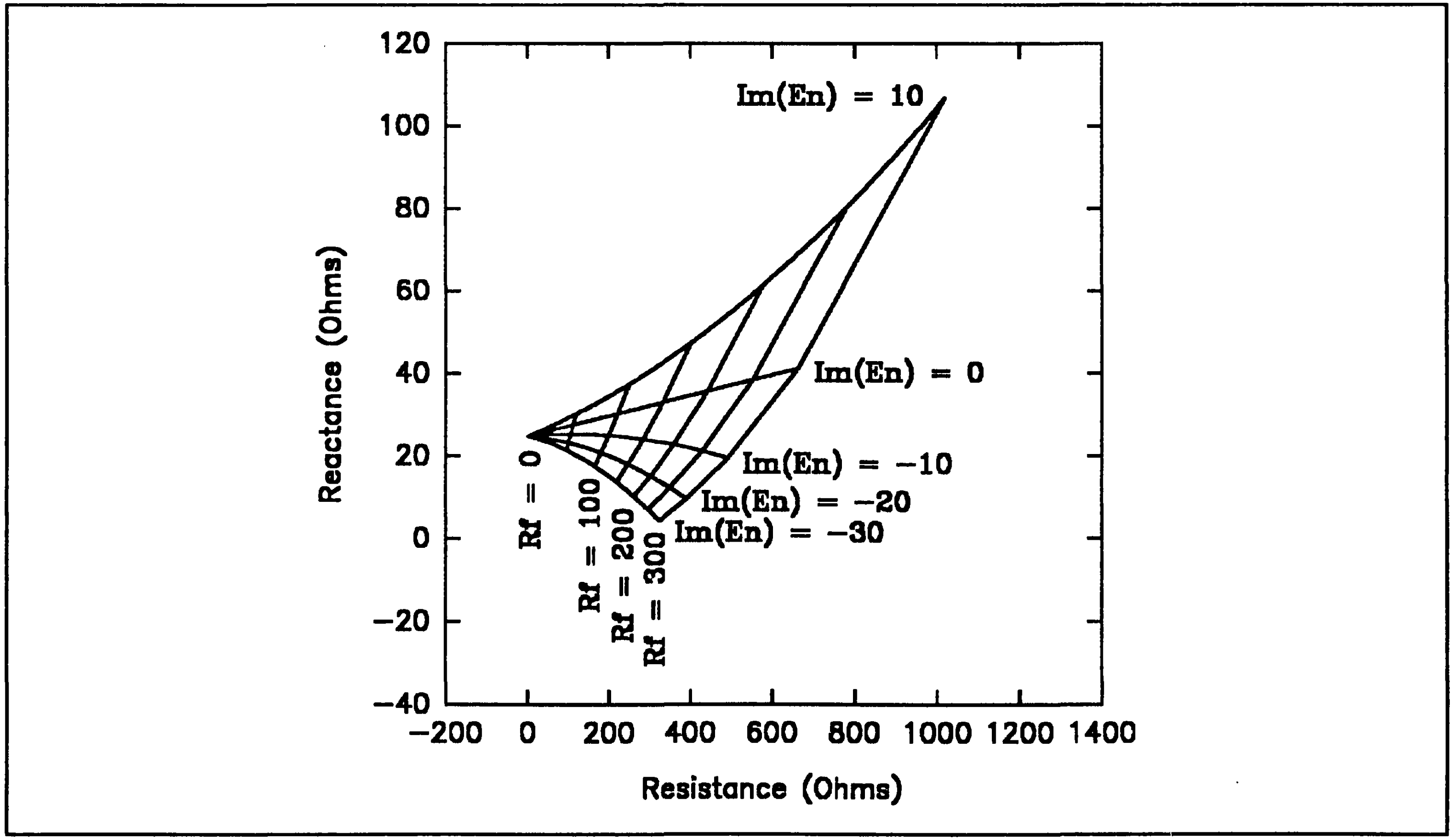

Figure 6.12 Influence of Variation of Reactive Voltage of Source N with Fault Resistance

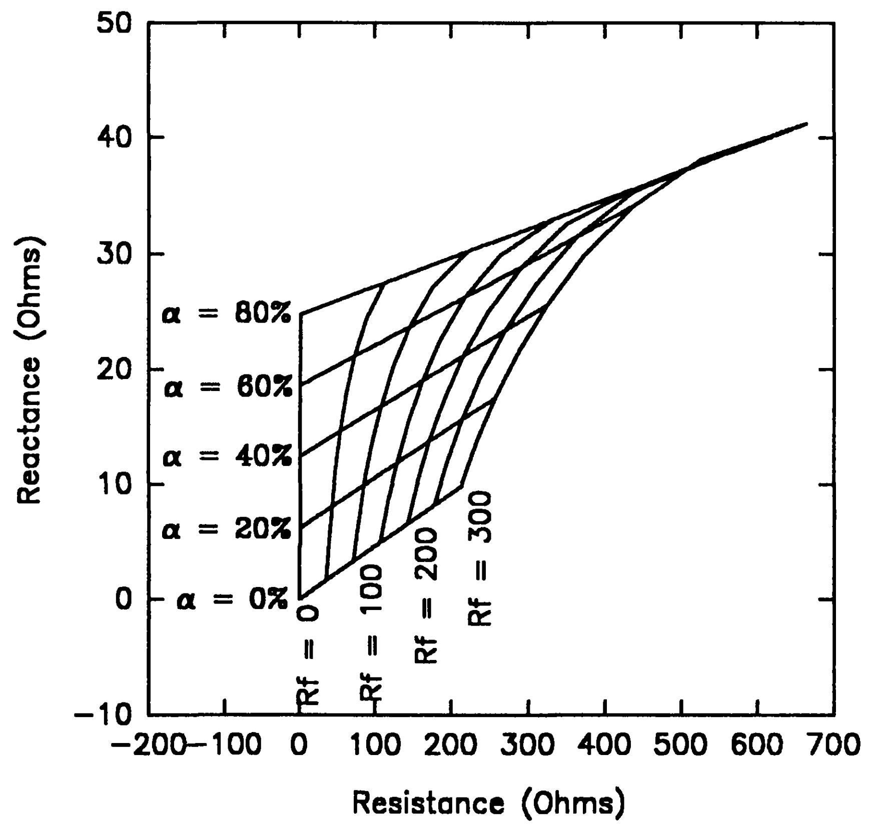

Figure 6.13 Influence of Variation of Fault Position with Fault Resistance

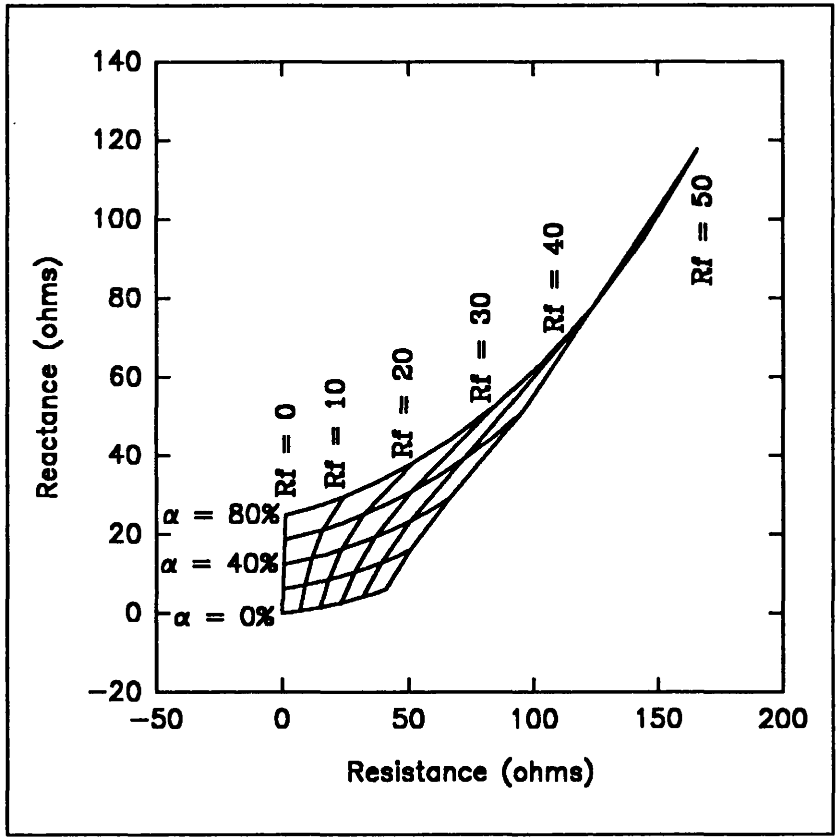

Figure 6.14.a Influence of Variation of Fault Position with Fault Resistance for Operating Conditions of Pre-fault Importing Load

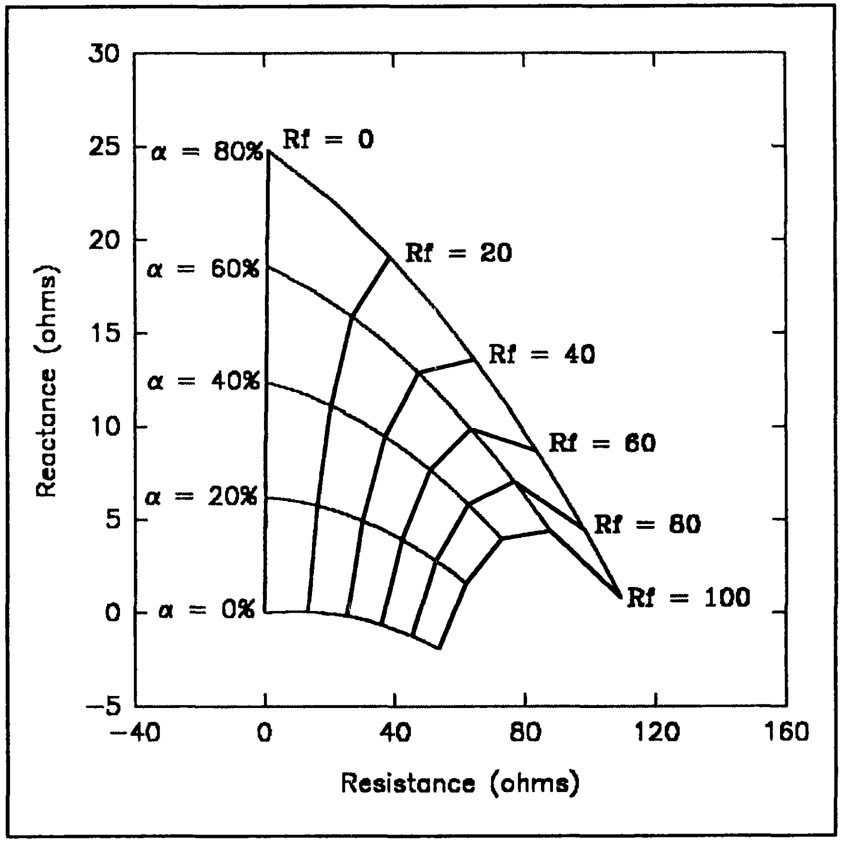

Figure 6.14.b Influence of Variation of Fault Position with Fault Resistance for Operating Conditions of Pre-fault Exporting Load

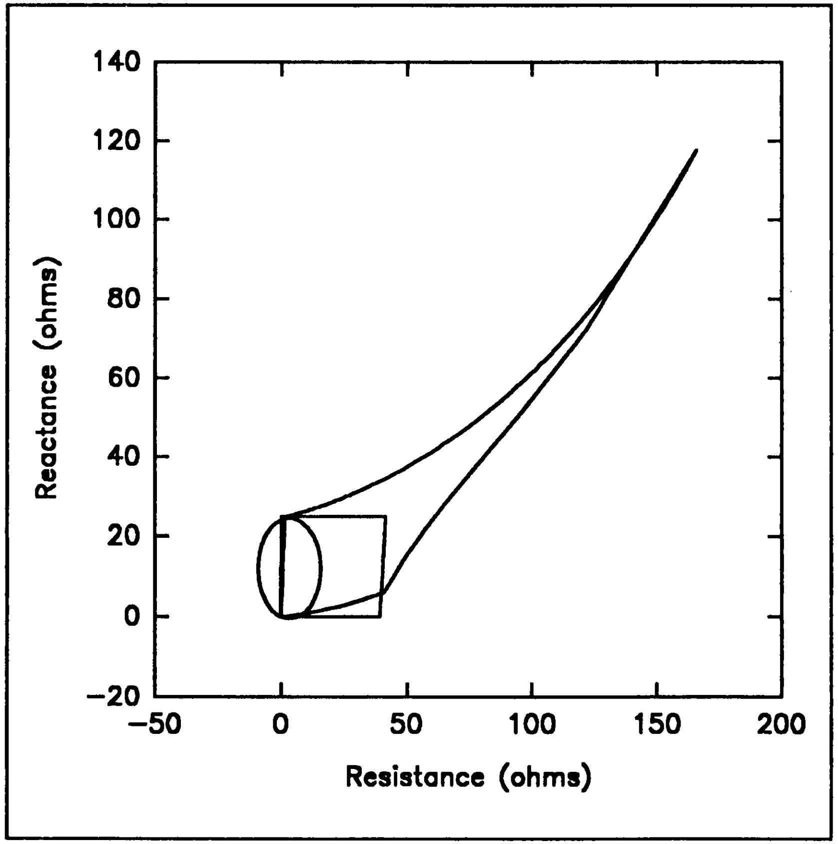

Figure 6.15.a Influence of Variation of Fault Position with Fault Resistance for Operating Conditions of Pre-fault Importing Load

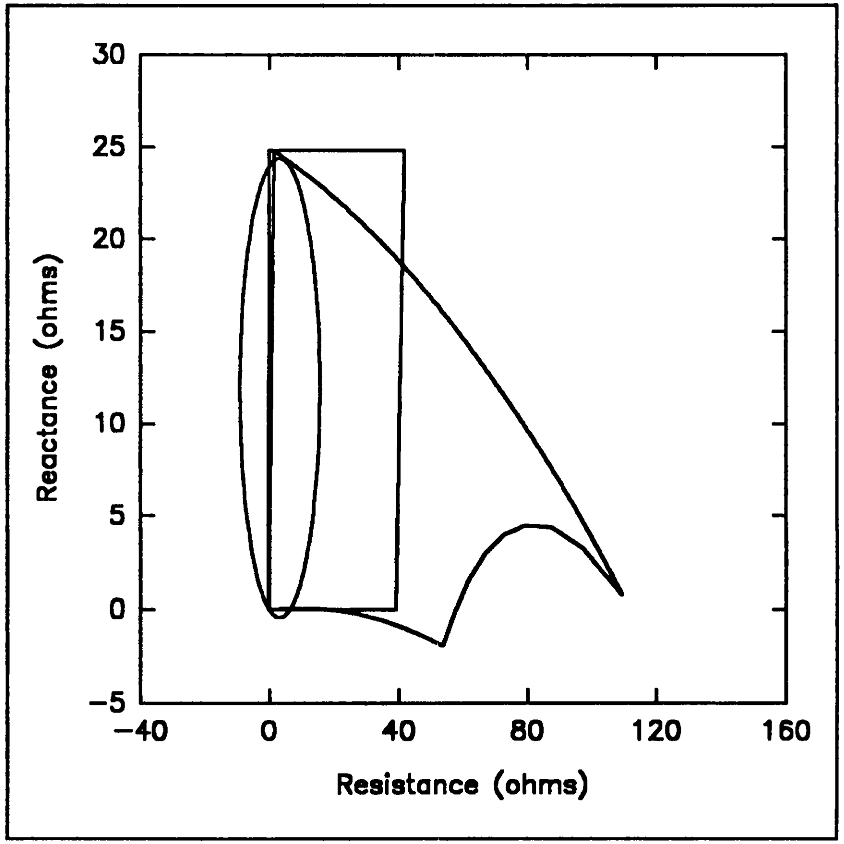

Figure 6.15.b Influence of Variation of Fault Position with Fault Resistance for Operating Conditions of Pre-fault Exporting Load

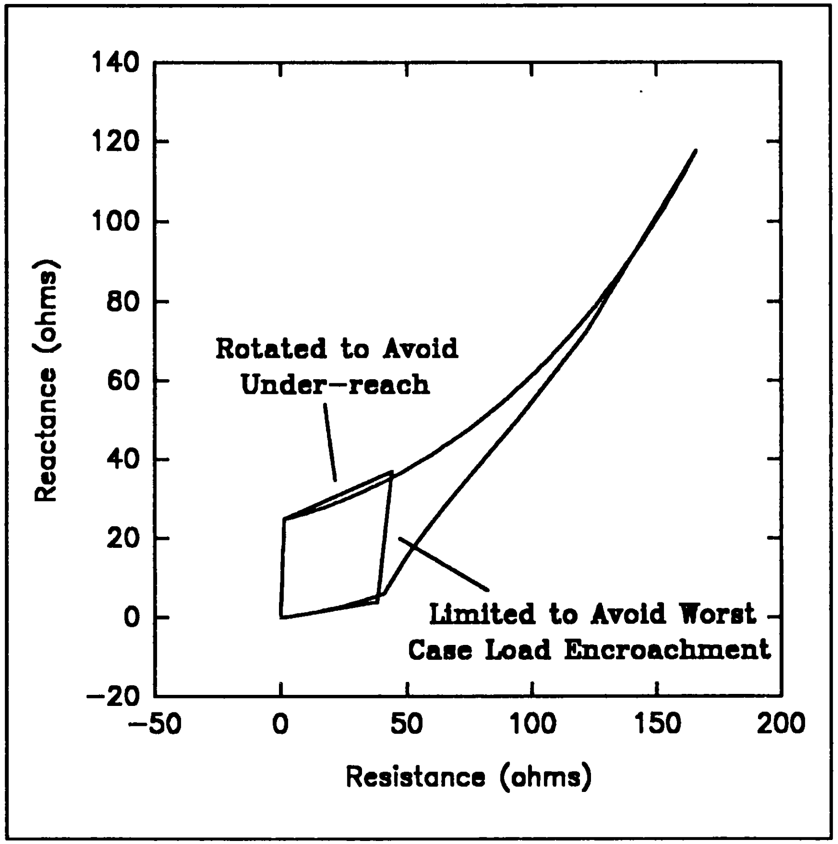

Figure 6.16.a Influence of Variation of Fault Position with Fault Resistance for Operating Conditions of Pre-fault Importing Load

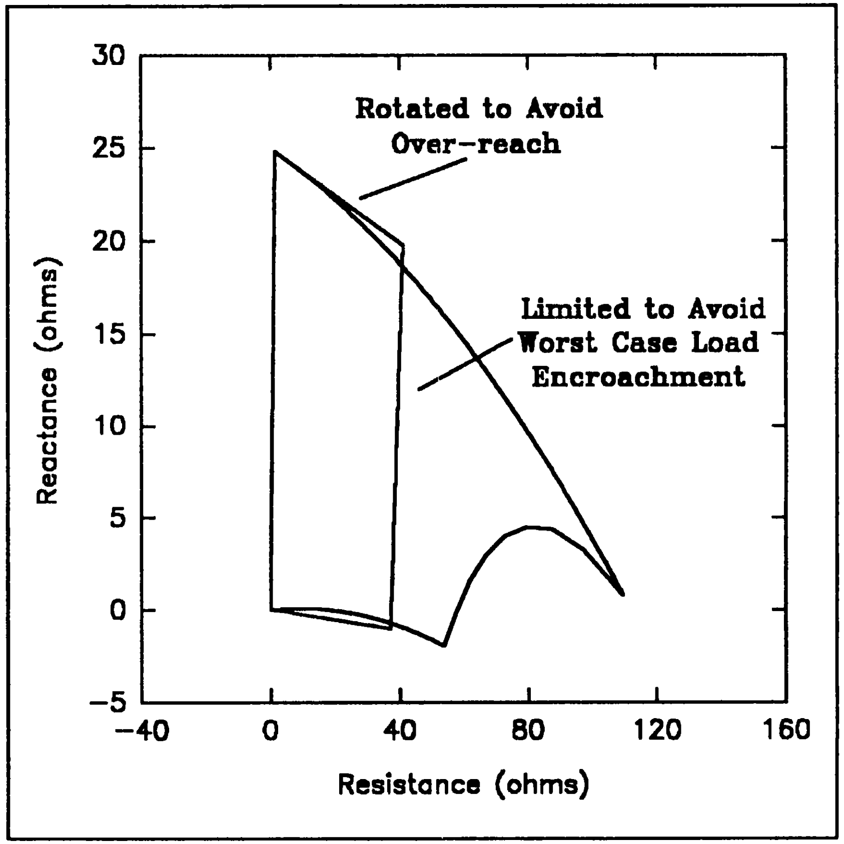

Figure 6.16.b Influence of Variation of Fault Position with Fault Resistance for Operating Conditions of Pre-fault Exporting Load

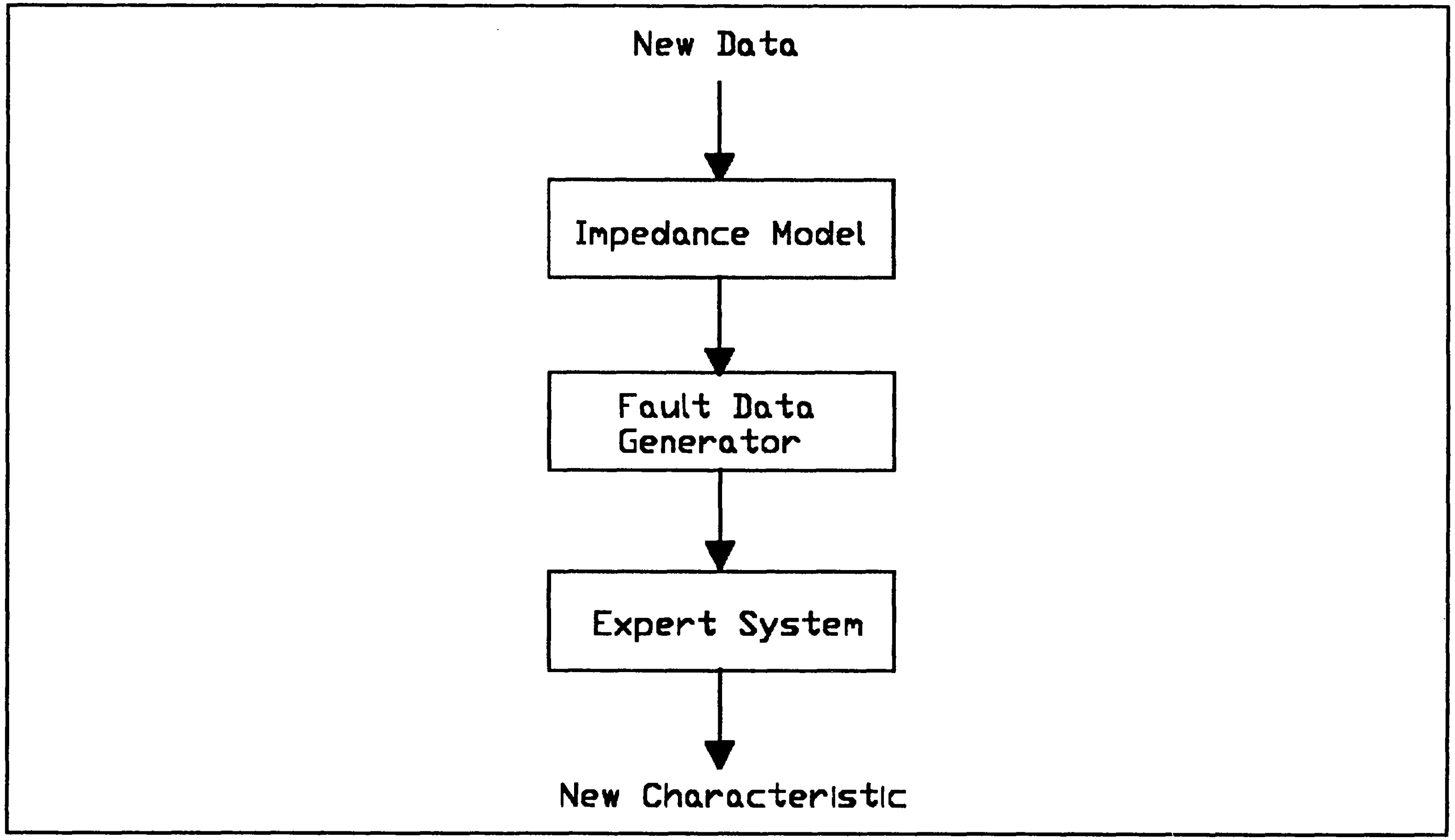

Figure 6.17 Structure of System Software for Characteristic Adaptation

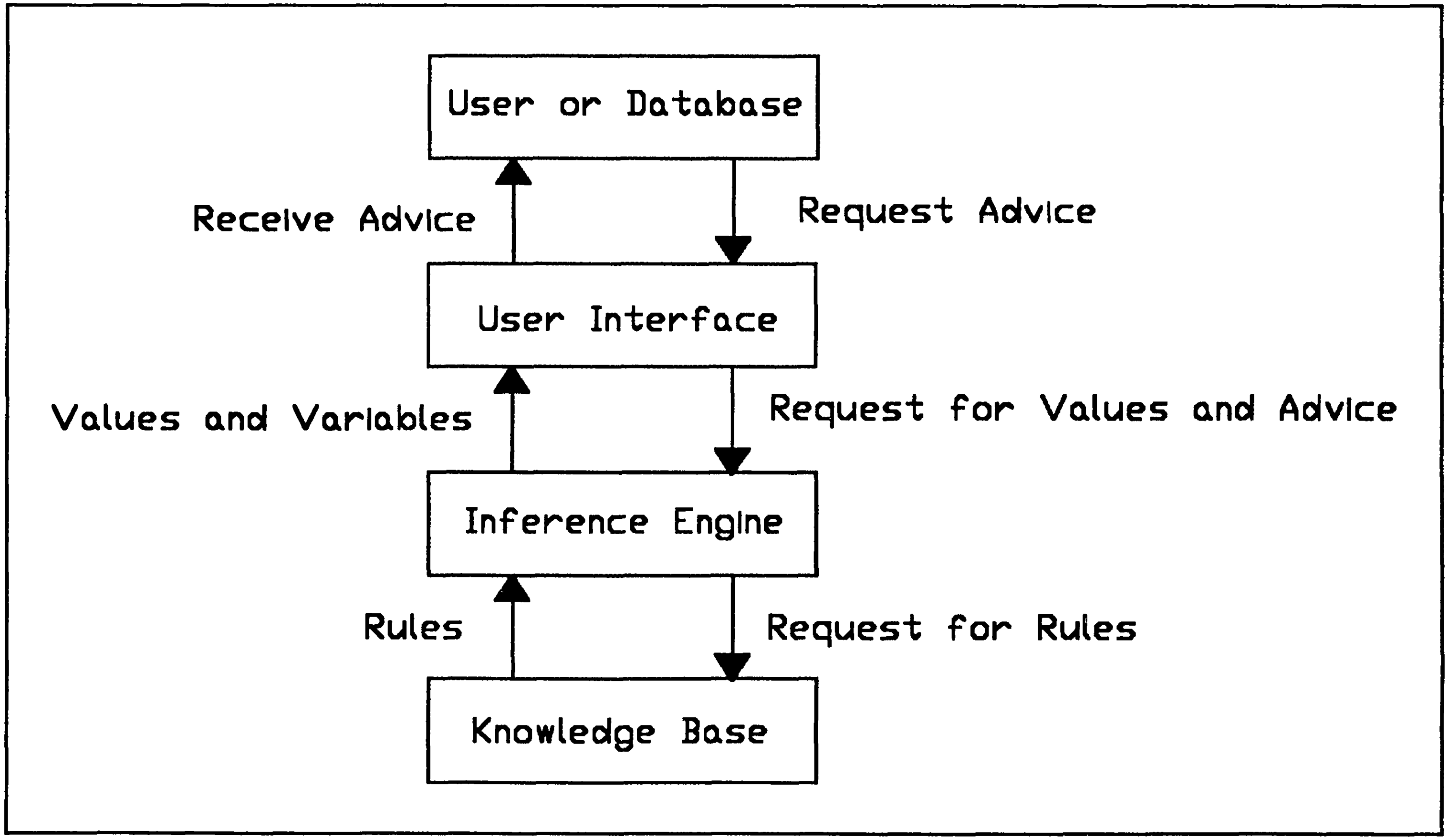

Figure 6.18 Configuration of an Expert System

CHAPTER 7

SIMULATION

7.1 Introduction

To illustrate the potential performance benefits of an integrated digital hierarchical control and protection system two applications have been developed. The first of these applications simulates an integrated digital hierarchical control and protection system for the adaptive setting of distance relays. The second application illustrates the influence of high resistance earth faults on the residually compensated element of a distance relay and enables adaptation of the characteristic within a hierarchical environment to overcome limitations of conventional systems. Each of the applications is discussed in more detail in the following sections.

7.2 Application for Simulation of an Integrated Digital Hierarchical Control and Protection System for the Adaptive Setting of Distance Protection Relays

7.2.1 Introduction

In chapter 5 it was shown how changes in the power system operating conditions influenced the apparent impedance measured by distance relays. A method for the adaptive setting of distance relays, using a reduced impedance model located at the substation whose parameters were continually updated by the integrated digital hierarchical control and protection system was outlined. To enable analysis of the performance of such a system, a simulation has been developed.

Simulation of the integrated digital hierarchical control and protection system requires simulation of the power system and each of the individual components within the hierarchical protection system, some of which may be similar elements occurring more than once. The system comprises:

- the system computer.
- multiple substation computers.
- multiple protection cluster computers.
- multiple data acquisition units.

The operation of the elements in the integrated digital hierarchical control and protection system occur in parallel. Further, central to the implementation of the integrated digital hierarchical control and protection system is the efficient transfer of data between the constituent elements of the system. Ideally, a simulation of a hierarchical system would comprise a multi-processor environment with each of the individual processors representing the individual constituent components of the hierarchical structure and performing the task associated with that component. The inter-process communications are arranged hierarchically. Parallelism in a single processor environment may be simulated by time slicing or multi-tasking. To facilitate this, the integrated digital hierarchical control and protection system has been simulated in a Microsoft Windows.

Within the windows environment, the simulation is managed by the application window providing a visual standard interface to the user. The window is a combination of title bar, menu bar, scroll bars, borders and client area, the functions of which are well documented [7.1] and will be assumed to be known.

A menu driven interface provides the principle means of user input to the application. The functions of many of the commands are common to all applications running in this environment with application specific additions. The menu provides a list of commands that the user can view and choose from. Temporary windows, known as dialog boxes, provide simple input and output functions to direct the user in the utilisation of the application. For example, additional information necessary for the execution of a command is available via a dialog box. The functionality and use of the software is described in more detail in [7.2].

Prior to the implementation of any system it is necessary to carefully evaluate the benefit of the introduction of a system to the cost of implementing the system. In the context of this research it is necessary to compare the performance of a hierarchical control and protection system with traditional systems. The performance of distance relays may be analysed in two modes of operation:

- **Traditional Protection Relaying Mode**: In this mode of operation, the protection relays using conventional input measurands make a decision on whether to operate based on preset constant settings.
- **Adaptive Protection Relaying Mode**: In this mode of operation, the protection relays using conventional input measurands and information available via a hierarchical structure make a decision on whether to operate, where the settings have been adapted to reflect current power system conditions by using the additional information available. The adaptive setting of protection relays has been performed utilising two main methods:

    1) Setting the relays using variations of the NGC Setting Strategy.
    2) Optimisation of the Setting in terms of protection reliability.

The various setting strategies used have been outlined in chapter 5.

The simulation has been validated to the satisfaction of NGC using Cavero's commercially available ZR20 software application [7.3].

7.2.2 Simulation of Modules within the Hierarchical Environment

Each of the elements within the hierarchical system (ie: system computer, substation computers, protection clusters and data acquisition units) are simulated by a child process of the main application window. Each of the processes has its own data associated with it in locally defined databases, the contents of which may only be changed by:

- communications with connected processes.
- input via the GUI.
- performance of power system analysis functions performed at different levels within the hierarchy.

It should be noted that the power system module is also a child window of the main application window. Although this module does not form part of the hierarchical protection system, its inclusion is necessary to generate the required data for input into the simulation. The functionality of each of the child processes, or modules within the hierarchical system, are outlined in more detail in the following sections.

7.2.2.1 Power System Model

The power system is simulated using simple power system analysis software to generate the required data for input into the integrated digital hierarchical control and protection system simulation. The suite of programs enables the determination of the state of the power system in pre-fault and post-fault network conditions utilising load flow [7.4] and short circuit analysis [7.5]. The dimensions of the systems that can be modelled are highlighted in Table 7.1. Whilst these may be limited, they satisfy the requirements necessary to meet the project objectives. The power system analysis software also enables modelling of tap-changing transformers and incorporates the effects of a number of winding configurations including DD0, DZ0, ZD0, YY6, DD6, ZD6, DY1, YD1, YZ1, ZY1, DY11, YD11, YZ11 and ZY11 [7.6].

It should be noted that the load flow algorithms employ single phase analysis. It is therefore assumed that all load and transmission lines are balanced. In addition, only 3-phase balanced faults can be applied to the system. Whilst this represents a limitation, especially as the single phase to earth fault is the most common, the 3-phase fault is generally regarded as the more severe and as such of more interest when considering protection setting.

7.2.2.2 System Computer Model

The system computer oversees the entire integrated digital hierarchical control and protection system, being located in the control centre. The system computer has knowledge of the entire system obtained by communicating with the substation computers including:

- current system topology derived from the circuit connectivity and knowledge of the current circuit breaker status.
- current system load flow information including voltage magnitude and angle and branch flows.
- physical parameters of all elements in the system.

Using this information, parameters for the reduced impedance models located in the substations are calculated and communicated to the substation.

7.2.2.3 Substation Host Computer

The station host computer communicates with the system computer to:

- Receive information relating to the status of the system relevant to the setting of the protection relays located in the substation.
- Transmit information relating to the status of the system obtained from the data acquisition units via the protection clusters to the system

computer.

The substation computer calculates the settings of the protection relays in accordance with the required setting strategy.

7.2.2.4 Protection Clusters

The protection clusters are located at the bay level and comprise a number of protection relays associated with power system elements within the substation. They collate the data provided by the data acquisition units for use by the substation computer and utilise the data provided by the station computer to adjust their respective setting values. Based on the current information available to the relays a decision to operate or remain restrained is made.

There are many protection relays within power systems that would benefit from additional data derived via a hierarchical structure including both unit and non-unit types. Within this simulation of the integrated digital hierarchical control and protection system, the modelling of protection relays has initially been limited to distance relays as this form of protection provides both main and backup protection features on the majority of feeders within the England and Wales transmission system. The modelled relay is a mho distance relay with operation determined utilising the phase comparator technique. The distance relay model enables visual representation of the power system conditions presented to the relay in both pre-fault and post-fault network conditions. The input data presented to the distance relay model include the vector quantities:

- pre-fault busbar voltage.
- pre-fault branch power flow.
- post-fault busbar voltages for a 3 phase fault.
- post-fault branch currents for a 3 phase fault.

Dependent on the mode of operation, the relay may be set locally enabling the implementation of a conventional protection system or remotely via the hierarchical structure. These settings include:

- zone 1 setting.
- zone 2 setting.
- zone 3 forward setting.
- zone 4 reverse setting.
- zone 2 timer setting.
- zone 3 timer setting.
- line angle.
- load angle.

7.2.2.5 Data Acquisition Units

The data acquisition units perform the necessary control functions on their associated circuit breakers and gather information directly from the system which is passed to the protection clusters via optical fibre communications link. Within the simulation, there are two types of data acquisition units, those associated with monitoring busbars, and those associated with monitoring branches and controlling their circuit breakers.

7.2.2.6 Information Transfer

The modules developed in the preceding sections have been developed as stand alone applications. However, to function in the hierarchical environment, each of the modules must have the ability to communicate bi-directionally with other applications such that it may both receive and transmit data as required. In previous sections, it has been stated that each of the modules has been simulated by a child process. Each child process has knowledge of the other child processes to which it is connected. Following a change in data, in a given process, a discrete message is sent to all other processes to which that process is connected.

7.2.3 Data Management

Central to the simulation of the hierarchical systems is the efficient management of information. It is well known that power system monitoring and control requires the processing and storage of large amounts of data. In the simulation of the hierarchical system the requirements for data storage are increased considerably by the need to store multiple copies of the same data at different levels within the hierarchy. To ensure the efficient management of memory, memory is dynamically allocated.

7.3 Application for the Illustration of Power System Operating Conditions on Distance Protection Under Resistive Earth Faults

In chapter 6 it was shown how the impedance measured by distance relays is adversely affected by earth fault resistance. The residually compensated distance relay element has been simulated in software operating in a Microsoft Windows 3.1 environment. The software simulates the measured impedance by the relay, under changing earth fault resistance, for different user specified power system operating conditions. The performance of the relay for a number of characteristics, in addition to the adaptive characteristic, can visually be illustrated for the different system conditions. The application demonstrates the influence of power system operating conditions, for the double end fed feeder shown in Fig.6.1. The application is menu driven, with support dialog boxes for data entry. This allows the power system to easily be configured to the required form. The detailed functionality of the application is described in [7.7]. As with the adaptive setting application, this simulation has been validated to the satisfaction of NGC using Cavero's ZR20 software application [7.3].

Table 7.1: Maximum Dimensions of Power System Elements	
Element	Quantity
Busbars	50
Generators	30
Shunt Reactors	50
Transformers	50
Transmision Lines	200

CHAPTER 8

BENEFITS AND LIMITATIONS OF INTEGRATED DIGITAL HIERARCHICAL CONTROL AND PROTECTION SYSTEMS

8.1 Introduction

The power supply system of the United Kingdom is one of the largest and most highly integrated in the world. The introduction or replacement of equipment in the power system requires consideration of many factors, some of those to be considered including quality, safety, environmental impact, community attitudes, labour management relationships, cash flow position, risks, system reliability, system availability, system maintainability, system operability, system flexibility, impact on personnel levels, training requirements, comparisons with competitors, impact on different units within the organisation, customers preferences, capital requirements and economic justification [8.1]. Some of these issues are easily quantifiable and the decision to invest in new equipment is easily justified. For example, consider the scenario in which protection equipment is placing constraints on the operation of the power system. Here, the constraint may be quantified, say in terms of lost revenue, as can the cost of investment in a new protection scheme that eliminates the problem. The decision to invest in the new equipment will only proceed if cost of the new protection system is less than the cost of continuing to operate the system with the constraint over a defined period. Investment in other equipment requires more careful consideration as it provides benefits that are perhaps intangible and not so easily quantified.

This chapter describes the benefits and limitations of integrated digital hierarchical control and protection systems and justifies the decision to invest in such a system. This is undertaken in a framework that recognises that there is often more than one solution to engineering problems. The benefits and limitations of integrated digital hierarchical control and protection systems and alternative solutions are outlined by considering issues that power system operators are increasingly paying more attention to. It is shown that the integrated digital hierarchical control and protection system has considerable benefits over the alternatives and makes a significant step forward to the realisation of the totally integrated business system.

Economic considerations play an important part in decisions of investment alternatives. In relation to this work, the question remains as to whether the costs of investment in a integrated digital hierarchical control and protection system are justified. A method of cost justification that compares the cost of the integrated digital hierarchical control and protection system against alternative solutions is outlined.

8.2 Comparison of Integrated Digital Hierarchical Control and Protection Systems and Alternative Systems

8.2.1 Framework for Establishment of Benefits and Limitations of Alternative Schemes

Like all systems, to remain effective and provide services that the market requires they must continually evolve. This requires investment in new power plant, control equipment or protection schemes. Changes within the power industry have enabled private generating companies to emerge, requiring connection to the grid system of England and Wales. Power system operators must respond quickly to connect new generating stations and adapt the transmission system accordingly. The connection of new generating plant and the emergence of more complex transmission circuits, due to economic and environmental considerations, has meant that methods must be found to:

- Make the system easier to manage.
- Enable the system to respond more easily to changes in the power system and adapt to expansion.
- Enable the system to respond to changes in market demands quickly and efficiently.
- Improve the integrity and quality of supply.
- Reduce costs of operation and replacement of equipment.

- Enhance performance.
- Enable better utilisation of assets in the organisation, particularly expensive power equipment.

These issues may be addressed by investment in new equipment. Before investment takes place, it is necessary to formulate alternative solutions to address the issues, analyse the alternatives, and select a solution. The alternative solutions formulated are based on both conventional and digital solutions and include:

Solution A	do nothing.
Solution B	invest in a conventional stand-alone protection systems employing traditional technology.
Solution C	invest in a digital stand-alone protection systems employing smart technology.
Solution D	invest in a conventional integrated hierarchical control and protection systems employing traditional technology.
Solution E	invest in a integrated digital hierarchical control and protection systems.
Solution F	invest in power plant for system reinforcement.

The first of the alternatives, Solution A, is the "do nothing" solution. This involves continuing to operate the system with the same equipment that is already installed. This solution provides a bench mark for comparison of investment proposals. It is important to recognise that the "do nothing" solution also has benefits and limitations when compared to alternative solutions. For example, whilst it does not have an investment cost, its performance may be lower and the costs associated with operation and maintenance may be higher.

The remaining solutions, Solutions B to F, require investment in equipment. In Solutions B, the current equipment is replaced by a conventional system with the same principles of operation. As such, the protection remains operating in a stand-alone configuration. Solution C is similar to Solution B, in that the relays remain stand-alone. However, the latest digital relays employing enhanced signal processing techniques and smart technology are used. Solutions D and E form an integrated environment using conventional and digital relays respectively. The final alternative, Solution F, is very different. This alternative is included as one of the reasons for investment may be that the existing power plant is being utilised to its maximum allowable potential that current conventional protection system performance allows. Thus, instead of investing in improving control and protection system performance, to obtain further utilisation of the power plant, an alternative could be to invest in additional power plant operated at the current allowable levels of utilisation.

The decision to invest in either of these alternatives will depend on the benefits and limitations of each system and these must be analysed in detail. Key issues that relate to the alternative solutions have been identified that provide both tangible and intangible benefits to the power system operators. Each of these is discussed in the following sections, where relevant, and a comparison is made between the alternative solutions.

8.2.2 Installation Costs

The majority of equipment for the protection, monitoring and control of the power system is located in the substation. In the conventional system the protection, monitoring and control equipment, employing conventional (Solution B and D) or smart technology (Solution C), is located in a central switching room. Wiring from the transducers must come through the switch yard to the switching room. This has a number of disadvantages as:

- large amounts of wiring are required to interface the power system to functions being performed in the switching room.
- the wiring is subject to the hostile switch yard environment.
- each substation is different and a large proportion of work needs to be done at the substation when installing and commissioning equipment.
- complex decision logic requires large quantities of hardwired logic relays.

In contrast, in the digital integrated hierarchical control and protection system substation (Solution E):

- data acquisition units are located close to the transducers such that wiring is considerably reduced, the interface to the remainder of the system being done by a single digital communications link.
- advanced digital techniques with error correction using fibre optic cables can avoid interference in the hostile switch yard environment.
- the highly modular approach of the integrated digital hierarchical control and protection system enables the majority of equipment testing to be undertaken before leaving the factory.
- complex decision logic is easily accommodated in software.

The costs associated with plant reinforcement, Solution F, are discussed in more detail in section 8.2.5. However, for completeness it should be noted that the costs of power plant reinforcement are far greater than those associated with the installation of protection and control equipment.

It should also be noted that the "do nothing" alternative, Solution A, has no installation cost as the equipment is already in place.

8.2.3 Flexibility

Power systems are never designed and constructed in their ultimate form. Changes in demand and addition of generation require system reinforcement and corresponding changes to the protection and control system. In conventional control and protection systems, employing either smart or traditional technology (Solutions A, B, C and D), these changes are difficult to accommodate. However, the modular approach and mechanisms by which the additional data required on expansion are accommodated in a integrated digital hierarchical control and protection systems (Solution E) make it flexible enough to facilitate these changes with a minimum of effort and expense. Importantly, the integrated digital hierarchical control and protection systems enable evolutionary incorporation into old systems to avoid excessive expense.

8.2.4 System Utilisation

Modern power systems operate far closer to stability and thermal limits than was the case a number of years ago. To facilitate this comprehensive monitoring and control is essential to enable detailed analysis and modelling to determine if re-configuration and readjustment is required. In addition, protection, control and monitoring equipment must meet more stringent performance criteria. The integrated control and protection systems (Solutions D and E), by virtue of integration of information, provides a convenient framework in which this can be undertaken. Conventional control systems, using SCADA systems, also enable this. To a limited extent, conventional digital protection systems employing smart technology (Solution C) will enable improved utilisation as a result of improved performance achieved by more detailed analysis of existing information. However, conventional protection systems, employing traditional technology (Solution

B), would not enable improved system utilisation.

8.2.5 System Reinforcement

The cost of investing in power plant together with increased emphasis on environmental issues has meant that utilities are increasingly trying to defer system reinforcement of the transmission network resulting in the network being run far closer to thermal and stability limits as outlined in the previous section. It is important to recognise that the cost of introducing new control and protection systems (Solutions B to E), are small in comparison to the investment, say the £0.5M to £1.0M per km of double circuit 400 kV transmission line, required for reinforcement (Solution F).

8.2.6 System Management

In complex systems, the issues of management become far more complex. To keep out-of-merit operation of generation plant to a minimum, it is essential that maintenance and refurbishment programmes for the entire system coordinate with one another. In addition, these should be minimised. In conventional systems, maintenance is performed on a regular basis (Solutions A, B and C). In the integrated systems (Solutions D and E) the integration of information coupled with the inherent self monitoring capability of digital relays (Solution E) enables optimised determination of maintenance requirements based on say statistical information. In addition, the integrated digital control and protection system incorporates comprehensive information displays together with event and waveform recorders to monitor and log events to enable identification of past and future problem areas.

8.2.7 Unattended Operation

Some substations are situated in remote areas. To avoid having on-site operators, coupled with the need for systems to respond quickly, requires equipment that can be remotely interrogated and controlled. In addition, should communications fail, the remote substation should have the necessary intelligence to operate independently. Both of the proposed hierarchical control and protection systems, using either conventional or digital technology, are capable of performing this (Solutions D and E).

8.2.8 Redundancy

There is considerable commonality in both input and output quantities for performing monitoring, control and protection functions. In the conventional control and protection systems each of the functions is undertaken by a separate redundant sets of transducers - say one set for monitoring, one set for control and one set for protection (Solutions A, B and C). The integrated environment (Solutions D and E) reduces the redundancy by exploiting the commonality of information between functions such that there will be one set of transducers to enable integrated monitoring, control and protection of the system whilst maintaining levels of reliability.

8.2.9 Complexity

In the conventional system, a large proportion of the protection functions are performed by discrete, stand-alone devices (Solutions A, B and C). These perform simple tasks and act autonomously. The addition of communications links to these and the changing of their functionality adds considerable complexity to the system, as in the case of integrated systems, and increases the number of modes of failure (Solutions D and E).

8.2.10 Technology

The technology used in the conventional control and protection system (Solutions A and B) has evolved over the last century. These methods are tried and tested and as such well proven. The concepts of digital relaying (Solutions C and E) and integrated systems (Solution D and E) from which hierarchical control and protection systems are derived only came into existence in the 1970s. More importantly, their application to power systems is recent and there still remains a large body of work to be undertaken, some of which the technology does not exist for. To fully exploit the benefits of integrated systems devices whose functionality can be adapted and optimised on-line via digital communications link must be developed.

8.2.11 Availability of Information

The control and protection actions are directly correlated to the information which they are supplied with to make the decision of what action they should take. The stand-alone devices only have available to them conventional input measurands and as such the performance can only attain a specific level (Solution A and B). By using enhanced signal processing techniques for parameter estimation and system identification extra information may be derived from the conventional input measurands and the decision action may be improved (Solution C). Artificial intelligence techniques may also be used for extracting further information from the locally available information. Further performance enhancements and additional functionality may only be achieved by supplying the control and protection devices with additional information via the integrated control and protection system (Solutions D and E). For the protection system, these performance enhancements may prove particularly beneficial if say there was an area in which the occurrence of high resistance earth faults was proving influential in the integrity of the power system operation. Whilst the attainment of 100% performance is desirable, the economic and practical implications must be carefully analysed with regard to necessity and complexity. Where protection mal-operation leads to statistically significant risk of loss of supply, a lost revenue of £2 per kWh lost can be assumed.

The availability of this information will also create other uses for it. This could be commercially made available to other parties for their use.

8.2.12 Rationalisation

Fault initiated automatic switching schemes can be used to prevent overload, maintain dynamic stability, maintain transient stability, or maintain voltage stability. These schemes are increasingly being adopted in parts of the system where capacity is being stretched to the limit or where delayed reinforcement has led to particularly weak connections (ie: delaying Solution F). In these areas protection arrangements are complex and there is interaction between the control and protection schemes in the locality. The environment available in the integrated system enables a rational approach to the optimisation of fault initiated automatic switching and protection schemes. In a more abstract sense, the integrated control and protection system enables a more rational and effective flow of information throughout the organisation (Solutions D and E).

8.3 Cost Comparison Analysis

In section 8.2.1, it was stated that before investment takes place, it is necessary to formulate alternative solutions to address the issues, analyse the alternatives, and select a solution. The solutions were formulated and qualitatively analysed in sections 8.2.2 to 8.2.12. Whilst qualitative analysis is important, it is equally important to quantify in economic terms each of the costs associated with each of the alternatives.

In evaluating each of the different alternatives, an approach that compares a number of alternatives over a period of time is advocated. This is necessary as each alternative may have very different requirements of initial investment and recurring operational expenses. These issues are further complicated by the time value of money [8.1] in which money available now has a different value to money available at an alternative date. A step-by-step procedure is recommended for evaluating each plan [8.2] as summarised in Fig.8.1.

In this procedure, an area is chosen which requires development to alleviate limitations of existing equipment or replace equipment that has exceeded its lifetime. Alternative plans must be developed that meet the requirements of the utility. A study period must then be chosen over which the benefits and limitations of each of the plans is to be evaluated. The anticipated changes in the area must be projected over the study period. Using each of the proposed plans, the operating and maintenance costs for each year must be calculated incorporating the phasing in of the new systems such that the cost benefits can be shown. Each of the alternatives must then be evaluated by deriving the cost relative to the benefit gained and then compared with one another. In evaluating the alternatives it is important to quantify all costs including not only those associated with operation and maintenance but also those that are less tangible:

- Feeder Failure rate per year per mile.
- Line crew rate per man-hour.
- Savings introduced by improved performance.
- Savings introduced by improved availability of information.

- Savings introduced in generation by using generation production costing programs.

The costs of introducing an integrated digital hierarchical control and protection system depend on the extent to which integrated arrangements and digital control have already been installed at the relevant substations. In the England and Wales system, the necessary system data and central computing power is already available at the national and area control centres. The communications channels to the control centres for hierarchical control and protection are becoming available. Assuming the adoption of an integrated substation, the main costs of introducing the hierarchical control and protection arrangements are those required for the development and commissioning of the necessary software. This cost is not trivial in view of the complexity of the logic and the overriding need to demonstrate software reliability. The benefits that the integrated digital hierarchical control and protection system will show are in three principle areas:

- **Power System Investment:** The need for generation, transmission and distribution system reinforcement can be deferred. Conventional control, protection and monitoring equipment will be displaced by investment in the integrated system enabling flexible modification and addition to the system.
- **Power System Operation and Maintenance:** Interruptions will be minimised by reducing the time for the location of faults and avoiding the

need for unscheduled visits to substations. Commonality in hardware will make trouble shooting easier. This in turn will reduce losses in revenue. The quality of supply to the customer will improve by reduction in prolonged outages and improved reliability. Reduced repair and maintenance together with optimum operation of the system will reduce operational costs.

- **Improved Operation:** Comprehensive information, such as sequence of events, will be available to the engineer for analysis. This will enable improved planning and response during emergencies. Mal-operations will be reduced by the adaptive capability of relays enabling settings to be easily changed and flexibility in defining relay operational characteristics and functionality.

The area that has been chosen for development is the North Wales 400 / 275 kV network. Using data published in [8.3] together with the assumptions listed below, a comparison of costs has been undertaken.

- the costs of operation and maintenance for the "do nothing" alternative (Solution A) are the same as those for the new conventional stand-alone system (Solution B).
- the costs of transformer, busbar and shunt reactor protection are the same as those for line protection in the stand-alone investment alternatives

(Solutions B and C) as no data is available for this equipment.

- the factors associated with the reduction in maintenance costs and the reduction in unscheduled visits to substations for the stand-alone alternatives (Solutions A, B and C) have been assumed as no data is available.
- the cost of power plant reinforcement (Solution F) has been discarded as it is far more expensive than the other alternatives.

Based on a study period of 20 years and using estimates of costs [8.3] the cumulative costs for each alternative, assuming no increase in the cost of operation and maintenance and no consideration for the cost of finance, are illustrated in Fig.8.2.

Fig.8.2 assumed that there was no cost associated with borrowing for investment. However, finance does have a cost. If it is assumed that an initial amount P is borrowed at an interest rate of i % a year and that at the end of each year an amount R is paid back for n years until the dept is repaid, to ensure capital recovery then the amount R repaid each year is given by [8.1]:

$$R = P.\left[\frac{i.(1+i)^n}{(1+i)^n - 1}\right] \qquad \textbf{8.1)}$$

If the cost of finance is incorporated in the comparison and it is assumed that an amount to cover the cost of the investment (excluding operation and maintenance) at an interest rate of 10% for 10 years the cumulative costs of each alternative are shown in Fig.8.3. The cost of finance is highlighted by the disconinuity in all curves between the tenth and eleventh years of the study when repayment of the loan is completed.

Both Fig.8.2 and Fig.8.3 have assumed that there is no increase in the costs of operation and maintenance. However, this is not the case. To incorporate the cost of operation and maintenance, assume that each year the costs of operation and maintenance increase by i % every year and the current costs are C. It can be shown that in n years time the future cost, F, will be [8.1]:

$$F = C.\left[\frac{(1 + i)^n - 1}{i}\right] \qquad 8.2)$$

If the cost of operation and maintenance increases are incorporated into the comparison and it is assumed that the associated costs are increasing at a rate of 10% per year, the cumulative costs of each alternative are shown in Fig.8.4.

This final illustration, Fig.8.4, shows that the investment in new equipment only starts to yield benefits over the "do nothing" alternative after about 15 years. At this time both of the digital alternatives (Solutions C and E) become more economic than the "do nothing" scenario. It is also at this time that the cumulative costs of investing in the integrated digital control and protection system (Solution E) as opposed to investment in the stand-alone digital system employing smart technology (Solution C) shows dividends. It should be noted that both conventional protection systems (solutions B and D) never become economically viable.

8.4 Conclusions

The long term investment in the integrated digital control and protection system provides the most attractive solution of the alternative schemes proposed. This chapter has demonstrated the benefits and limitations of the integrated digital hierarchical control and protection system over alternatives using both quantitative and qualitative arguments.

It should be noted that whilst this chapter has qualitatively outlined the benefits and limitations, and quantitatively compared the costs, of integrated digital hierarchical control and protection systems relative to alternative solutions, it remains to be established if the cost to benefit analysis also indicates that investment in the integrated hierarchical control and protection system is favourable. This has not been undertaken within this work.

This chapter has, however, shown that the integrated digital hierarchical control and protection system does provides a significant step forward in the realisation of the integrated business solution. In the long term, the potential benefits of the integrated solution are not in doubt due to its impact on installation cost, flexibility, utilisation, reinforcement, management, redundancy, reliability, rationalisation, enhanced functionality and widespread availability of information. What is of far more concern is how the utility moves from the system of today to the integrated system of the future and it is this that will be addressed in the following chapter.

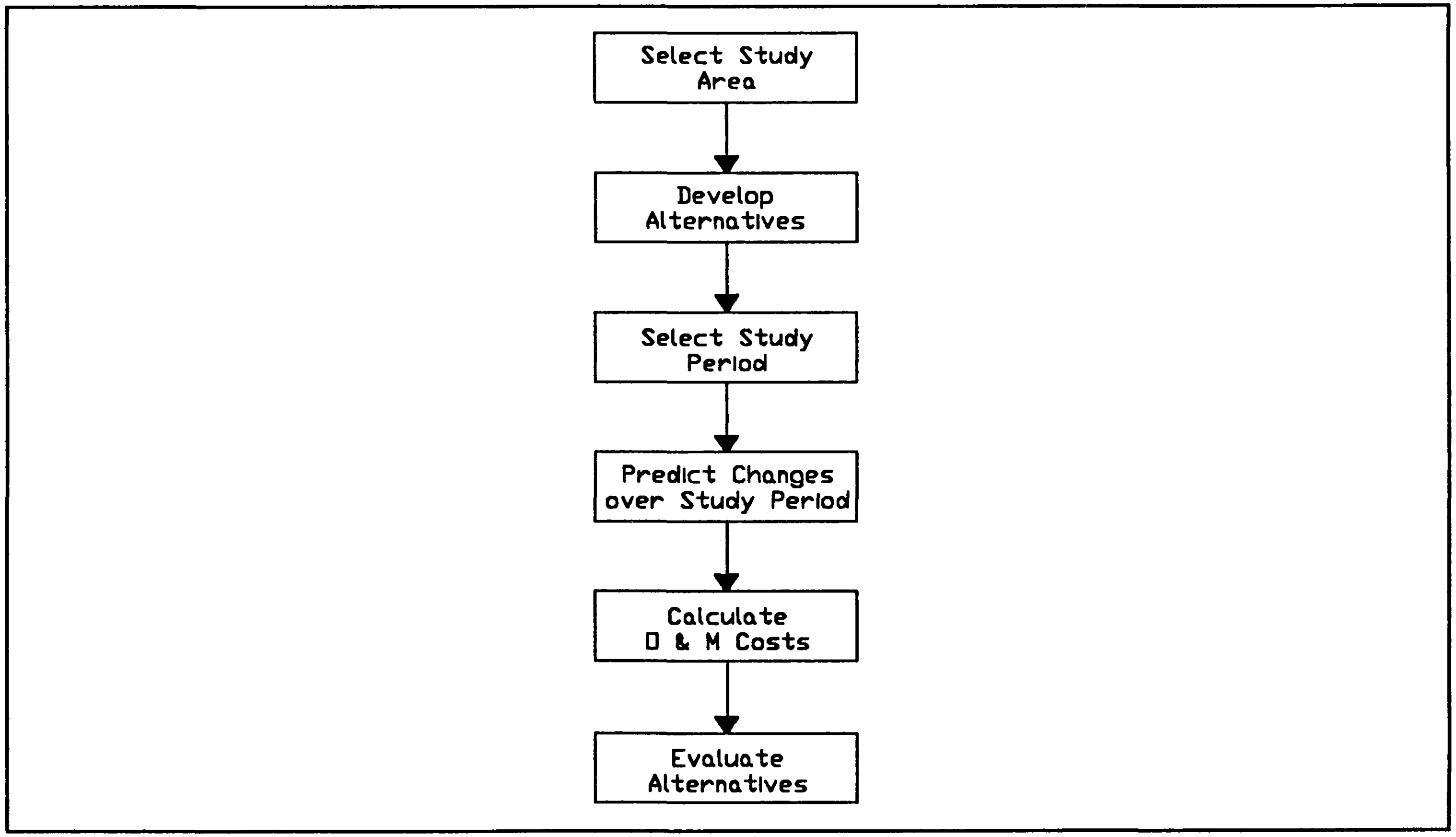

Figure 8.1 Rational Analysis of Alternative Solutions

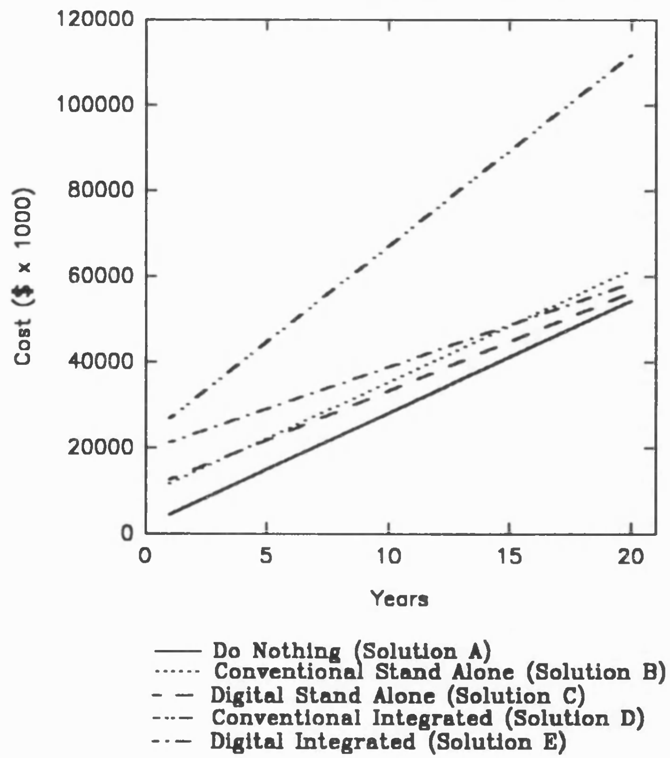

Figure 8.2 Illustration of the Cost of Alternative Solutions Ignoring the Cost of Finance and Annual Increases in Operation and Maintenance Costs

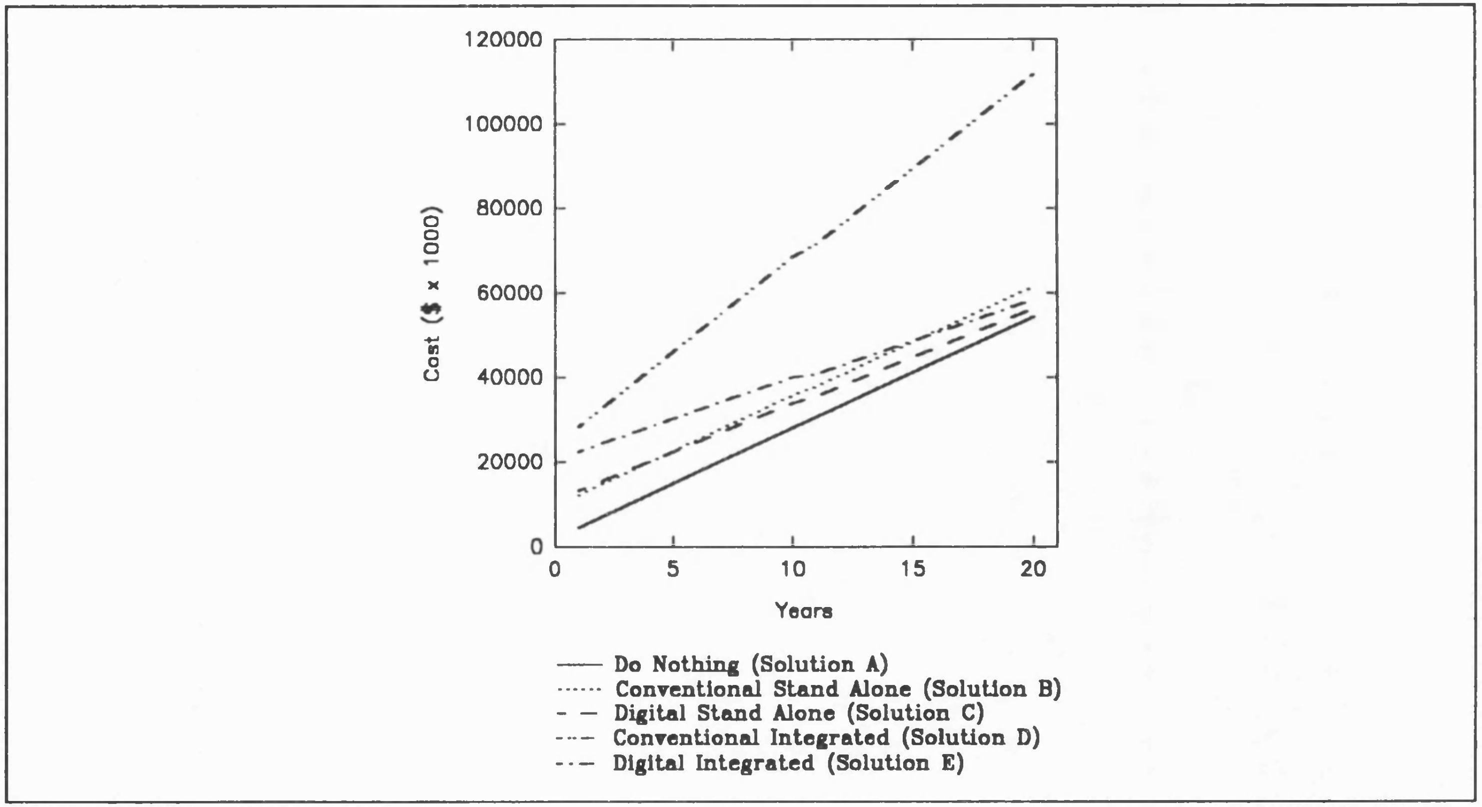

Figure 8.3 Illustration of the Cost of Alternative Solutions Ignoring the Annual Increases in Operation and Maintenance Costs

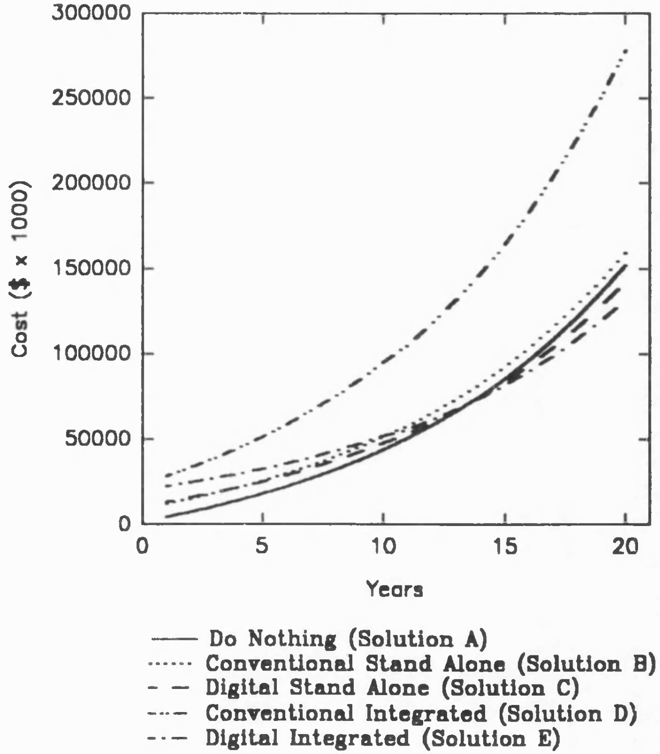

Figure 8.4 Illustration of the Cost of Alternative Solutions Including the Cost of Finance and Annual Increases in Operation and Maintenance Costs

CHAPTER 9

PRACTICAL IMPLEMENTATION OF INTEGRATED DIGITAL HIERARCHICAL CONTROL AND PROTECTION SYSTEMS

9.1 Introduction

Developments in digital electronics and communications have focused considerable attention on the application of this technology to power system control and protection. A wide range of microprocessor-based products are now commercially available for monitoring, control and relaying. New tools and concepts that exploit the greater flexibility and efficiency provided by microprocessor and communications technology, such as the integrated digital hierarchical control and protection system, have also emerged. However, the power system already incorporates a large complex infrastructure for performing the control and protection functions. To exploit the benefits of the new technology whilst introducing them in a cost effective manner provides one of todays greatest challenges [9.1].

This chapter starts by considering, in abstract terms, the steps necessary for the implementation of a integrated digital hierarchical control and protection system. A large proportion of business capital is already invested in control and protection equipment, much of which still performs its function correctly and has a number of years of its lifetime remaining. The enhancement necessary to the existing system and the method by which it should evolve to the new systems are outlined. The implications to computer hardware, software and communications are outlined. The technology of today still has its limitations and the requirements for developments and advancements are outlined. The chapter concludes by outlining some of the social issues that also need to be considered when introducing a new system.

9.2 Steps in the Implementation of the Integrated Digital Hierarchical Control and Protection System

The decision to invest in a integrated digital hierarchical control and protection system should not be taken lightly. It should be treated in exactly the same manner as the investment of any other piece of capital equipment. As in the introduction of any equipment, a rational approach incorporating feasibility study, requirements analysis, system design and implementation should be undertaken [9.2]. The objectives of each of these stages in the process are briefly outlined.

- **Feasibility Study:** The feasibility study provides an assessment of the business needs for the investment in the system and should conclude by stating whether the investment is justified. The motives for investment in the system and the main application areas should be outlined. This will enable evaluation of the benefits of acquiring a system and the cost involved. It has been the purpose of this document to address these issues.

- **Requirements Analysis:** Following the feasibility study, abstract requirements of the system will have emerged. Using this to provide a framework, a detailed specification should be drawn up defining the major objectives of the system, the applications for which the system will be used and how it will be expanded upon. The hardware requirements for visual display units, printers, storage, users, communication facilities and environment, and a timetable for implementation must be defined.
- **Design:** This incorporates the detailed design of the hardware and the organisation may wish this to be undertaken by external companies. In this case suppliers should be invited to tender and proposals evaluated considering the costs of hardware, software, support and training.
- **Implementation:** In parallel with the design, the organisation needs to carefully plan how the new system is going to successfully take over from the old system. This not only requires the resolution of technical issues but also human resource issues such as training and acceptance by the employees of the new system. On supply of the system, it must be configured and undergo considerable field tests before it can go on-line. Importantly, there must be a transfer period from the existing methods to the new systems.

9.3 Technological Issues in the Introduction of the Hierarchical Control and Protection System

9.3.1 General

The means and principles available for the control and protection of the power system of today have been outlined in chapter 2. The structure of an integrated digital hierarchical control and protection system has been outlined in chapter 4. The implementation of such a system requires careful consideration incorporating not only the functions that it is required to do today but also how it can evolve to new systems as the power system develops and matures. It is important to recognise that the integrated digital hierarchical control and protection system only integrates the control and protection functions. In time these systems will evolve to form a complete business system with all functions within the organisation integrated. To ensure that flexibility is built into the system to accommodate continuous development, a detailed knowledge of what thinking the business needs, what information is required in order to do this thinking, and what information must be supplied to the company on the basis of this.

The introduction of integrated systems will also have a considerable impact on the organisational structure. At the heart of introducing integrated systems is the flow of information. The departmental view of organisations must be discarded in favour of an approach aiming for the optimised flow of information through the organisation. This information must satisfy the requirements of the users so that:

- power system operators can use the information to run the system in a safe, secure and economic manner.
- protection engineers can easily analyse the performance of relays.
- maintenance departments interested in finding out the time in service and number of operations of plant can easily do so.
- accounting departments easily know how much energy has been purchased and sold.

Importantly, the system must be implemented such that it ensures profitability.

9.3.2 Implementation

The existing system provides a framework from which to develop the integrated digital hierarchical control and protection system. The practical implementation of the integrated digital hierarchical control and protection system requires evolution from the existing system. It will not come into existance following a "big bang". Rather, as and when existing equipment exceeds its lifetime or it becomes beneficial to do so, the integrated digital hierarchical control and protection system will more likely come into existance.

Steps in the implementation of the integrated digital hierarchical control and protection system are summarised in Fig.9.1. As the current system must evolve to the new integrated digital hierarchical control and protection system, the first step in the implementation must be the formulation of company policy that states that the long term objective is to move towards such a system. Importantly, the management must support these objectives by recognising why such a system is necessary. Based on this, all future investment proposals in the control and protection system must be geared towards realisation of the integrated digital hierarchical control and protection system.

On completion of this, the practical problems of incorporating the hierarchical control and protection system into the existing system must be addressed. A large proportion of protection and control devices are stand-alone and function independently. These devices still provide adequate functionality and are within their lifetimes. The ideal integrated digital hierarchical control and protection system requires access to all devices for efficient monitoring, optimisation and control. It is recognised that it would be impractical to undertake this at one time due to the financial implications. However, when the incentive of replacing the existing equipment with new digital equipment with communications features, due to the limitations on operating constraints and quality, then they will be replaced. Initially, the new digital control and protection devices will remain operating as stand-alone devices exploiting their enhanced performance made available by the latest signal processing and artificial intelligence techniques. These devices will then be connected together and interfaced to the regional control centres via a substation computer when:

- the proportion of these devices in each substation has increased.
- higher levels of performance, available only through access to further information available either within the substation or external to the substation, are required.
- the benefits of information integration outweigh the costs.

The necessary system data and computing power is already available at the national and area control centres. However, it does have a number of limitations and enhancements that are required to introduce the integrated digital hierarchical control and protection system.

- **Development of EMS:** The EMS is geared to power system control. The data available through SCADA must be made available for the optimisation of all protection and control functions.
- **Development of Software:** The optimisation of protection relay performance and the rationalisation of fault initiated automatic switching will require the development and commissioning of software at the control centres. This is not a trivial matter due to the complexities involved and the overriding need to demonstrate software reliability. This will require substantial investment.
- **Data Monitoring:** Central to extracting benefits out of the hierarchical system is the widespread availability of reliable information. This

information must be gathered via transducers and checked for integrity using state estimation techniques. On loss of certain sensors, the information currently available for state estimation can make the system unobservable such that the state of the system cannot be recreated. This must be overcome.

- **Communications Infrastructure:** The communications infrastructure currently comprises dedicated links for both protection and control. At present there is a minimum of one data channel and one voice channel from the area control centres to each substation. Dedicated inter-substation communications links for protection are also provided. Whilst these are sufficient to provide the monitoring, protection and control, these need to be increased to accommodate the additional information flow in the integrated digital hierarchical control and protection system. With time these need to evolve to the new computer network methodologies for LANs and WANs. It is important to recognise that wide area public communications infrastructures are still developing and still use circuit switched technology. These will eventually evolve to the integrated services digital network (ISDN) providing both data and voice communications channels.

As this happens, the hierarchical infrastructure will emerge. It should be noted that in implementing the system the following should be considered:

- **Maintaining Supply:** The disruption of supply to customers can have significant financial implications. The new system must be introduced and take over from the existing system in a manner that maintains the integrity of supply.
- **Standardisation:** Standard methods must be used in the design and configuration of control and protection schemes.
- **Expanding the System:** Power systems are continually evolving. The practicalities of expanding the system and ensuring all relevant databases are updated within the hierarchical system whilst ensuring satisfactory levels of reliability must be carefully evaluated.
- **Relay Adaptation:** In adapting the relay, the relay may only have a finite range of adaptability. For example, only a limited number of stepped settings may be available for setting adaptation. The algorithms for calculation of the new setting must take this into considertion.
- **Interface Between Conventional and Integrated Digital System:** During the evolution of the existing system to the integrated digital hierarchical system, scenarios will arise in which information in the existing system that has not been upgraded is required in the new system and vice versa. Here it will be necessary to interface the two systems.

As the infrastructure of the hierarchical control and protection system develops, further developments in software tools to fully exploit the information available will emerge.

These developments will continue until all functions within the organisation have been integrated, leading to the realisation the of totally integrated business solution.

9.3.4 Requirements for Developments and Advancements In Technology

The history of power systems has been one of continuous development. To fully exploit the benefits to be gained by the introduction of the Hierarchical Integrated Control and Protection System, further developments are necessary in the following areas:

- **Control and Protection Devices:** Conventional control and protection devices have pre-specified functionality. To exploit the full benefits of the hierarchical control and protection system, devices must emerge whose functionality can be on-line adapted and optimised via digital communications links.
- **Artificial Intelligence:** A large proportion of functions within the organisation still require intervention by the human. The complete automation of these functions within the organisation requires that they be performed by the computer. Further work remains to be done in the use of these systems for the rationalisation of information and the automation of the decision process.
- **Interfaces:** The interface between the human operator and the computer has come a long way since the introduction of the computer with punch

card input and output. However, research in human factors engineering must continue to improve the integration of the human and the computer for more efficient and productive interaction.

- **Information Integrity:** The integrated digital hierarchical control and protection system is only as good as the data that is put into the system. Methods must be found to check and correct data within all databases to ensure high reliability operation of the system. For example, in adaptively setting a protection relay, the data upon which the new setting is calculated is subject to tolerances, say in transducers. It must be demonstrated that the new setting offers satisfactory levels of performance under these conditions. Furthermore, on changing the setting, it must be demonstrated that the new setting downloaded to the relay is the required setting and no corruption has taken place.

9.4 Social Issues in the Introduction of the Integrated Digital Hierarchical Control and Protection System

The increased levels of automation, afforded by the introduction of the integrated digital hierarchical control and protection system, have considerable social impact throughout the organisation from top management to unskilled labour.

Fewer but more specialised people will deal with complex problems aided by the computer and sound management and scientific principles. This will result in the thinning out of middle management and considerable changes in the company structure. The introduction of automated systems will also move management culture. There will be a reduction in the concern with incentives to employees to increase productivity and a corresponding increase in the ability to maintain and extract better utilisation of equipment. This will result in the emergence of managers who have a broad combination of social, technological and economic skills.

The introduction of the system will bring about economies in labour and far reaching changes in the pattern of employment. The employees must be consulted about the effects of changes in working conditions. The need for unskilled labour is reduced, some existing skills being rendered obsolete. So far as reasonably practical, the workforce should be ensured that redundancy will be catered for by wastage and retirement.

The rate of technological development will be such that all levels of staff may need to be periodically retrained. The new system will place considerable demands for a high technical culture. This will require investment by the organisations, not only in facilities for providing training but also investment in the employees within the organisation. However, it is important to recognise that the development of automated systems will not depend on the computer technology but on staff familiar with the processes that make up the business they are involved with.

People will always resist change. Those responsible for the introduction of the new system must consult all employees who will be effected. It has been found that the change is accepted if they are consulted and made to feel part of the process. More importantly, a great deal can be learned and the organisation can benefit from the feedback recieved.

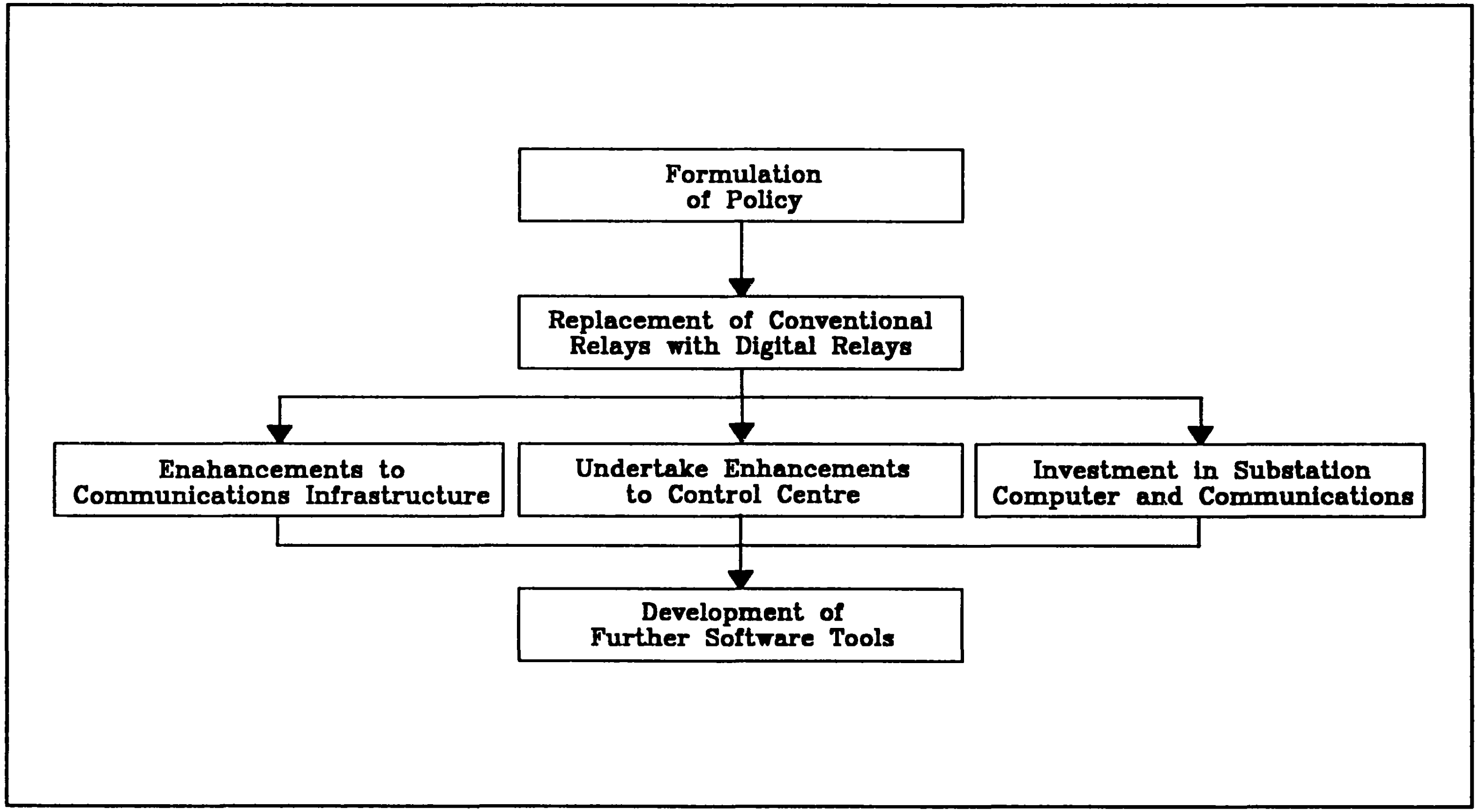

Figure 9.1 Steps in the Implementation of a Hierarchical Control and Protection System

CHAPTER 10

CONCLUSIONS

10.1 Achieved Objectives

The objectives of the research, as outlined in Chapter 1, were to simulate an integrated digital hierarchical control and protection system and to evaluate the potential benefits and limitations of introducing such a system to the North Wales 400 kV network forming part of the transmission system managed by NGC.

The above objectives have been achieved by:

(i) the development of software which simulates a hierarchical protection system based on the North Wales 400 kV network, and adaptively optimises the functionality of distance relay, and

(ii) by production of this document which describes integrated digital hierarchical control and protection systems and their application to optimise the functionality of distance relays by adaptive techniques.

Two techniques are described in the report and demonstrated by the software for adaptation of the functionality of distance relays. The first technique adapts the zone settings of distance relays and the second technique adapts their characteristic such that the fault selectivity of the distance relays are improved. The potential benefits of integrated digital hierarchical control and protection systems have also been described, together with the particular benefits and limitations of their application to distance schemes.

The objectives of the research have been met.

10.2 Principal Findings

The following is a summary of the conclusions drawn from the work:

(i) The overall financial cost of integrated digital hierarchical control and protection systems are less than contemperary conventional types of schemes. This is examined in Chapter 8. Notwithstanding this cost advantage, there are additional benfits associated with integrated digital hierarchical control and protection schemes which would result in better asset utilisation and system management.

(ii) Using an integrated digital hierarchical control and protection system, the work shows that techniques to adapt zone settings of distance relays and also to adapt their characteristic shape as the prevailing power system conditions change, were possible. The work also shows that this on-line adaptation would improve the performance of protection for certain fault conditions. This is demonstrated in Chapters 5 and 6.

(iii) The software developed satisfactorily demonstrates the workings of the adaptive techniques. The theoretical basis of the software was validated by NGC to their satisfaction using independently produced software.

(iv) The steps necessary to implement an integrated digital hierarchical control and protection system require careful planning. An approach that enables the existing system to evolve to the integrated digital hierarchical control and protection system has been discussed in Chapter 9.

(v) Further work needs to be undertaken in the application of integrated digital hierarchical control and protection system to power systems. This is discussed in section 10.4.

10.3 Summary

Whilst the control and protection systems already have high levels of performance, the power system of the United Kingdom is continually evolving and becoming more complex. Within this changing environment, techniques that maintain, and if necessary increase, the performance of the power system whilst making the system flexible, economic, responsive to changes, easier to manage and better able to utilise the assets of the organisation, are of considerable interest. The computer integrated system, by integrating information, provides a mechanism for this.

To provide a framework on which to base the research, the power system of the United Kingdom has been discussed. The concepts behind computer integrated systems and their organisation in the solution of large complex problems have been outlined. It has been shown that the computer integrated system arranged hierarchically should be employed in the solution of large problems such as that of a national power system. The functionality of the decentralised computing resources has been outlined in abstract terms. Supporting the decentralised computing resources are communications, database and artificial intelligence technologies. The principles behind these technologies have been discussed.

The integrated digital hierarchical control and protection system provides a mechanism for exploiting the benefits of the computer integrated systems for the control and protection of power systems. The increasing need for fault initiated automatic control switching for the alleviation of plant overload and stability problems have been discussed. The limitations of conventional protection systems have been discussed and the use of the integrated digital hierarchical control and protection system for the optimisation of protection performance by way of introducing adaptive protection have been discussed.

The use of adaptive protection systems for the optimisation of the performance of the functionality of relays has been outlined. The functionality may be altered via two principle means: the setting and the characteristic. The use of the integrated digital hierarchical control and protection system for adaptively changing the setting of distance relays has been outlined. Various methods have been discussed including methods using the National Grid Company setting strategy and methods optimising the reliability of the protection, the latter method considering the impact of settings on dependability and security. The performance of each of the methods has been shown. The use of the integrated digital hierarchical control and protection system for optimising the performance of distance protection under the influence of high resistance earth faults by using relays with the capability of changing their characteristics has been outlined.

To illustrate these effects two applications have been developed, one for the adaptive setting of protection relays and one for characteristic adaptation. The applications have been developed to operate in a Windows 3.1 environment and visually show the user the benefits and limitations of adapting the setting and the characteristic. Results have been presented that validate the software and provide a framework for discussing developments that are required to enable protection engineers to evaluate the performance of protection.

The introduction of new systems to the power system requires careful analysis of the benefits and limitations of introducing the integrated digital hierarchical control and protection system. These have been considered with respect to alternative solutions and in the long term the potential benefits of the integrated environment have been considered with respect to:

- Installation Cost.
- Flexibility.
- Asset Utilisation.
- System Management.
- Redundancy.
- Functionality.
- Reliability.
- Availability of Information.

It should be recognised that for businesses to fully exploit the benefits of automation, this requires not only the automation of functions of the control and protection but also the automation of all other business functions and how these functions are integrated. Whilst the integrated digital hierarchical control and protection system only integrates the control and protection function, it provides a significant step forward in the realisation of the totally integrated business solution.

Whilst the long term potential of computer integrated systems are not in doubt, what is of far more concern is how the utility moves from the power system of today to the integrated system of the future. It is recognised that the power system already incorporates a large complex infrastructure for performing the control and protection functions. The steps necessary in the implementation of the integrated digital hierarchical control and protection system and in particular, the enhancements that need to be added to the existing infrastructure are outlined.

10.4 Further Work

There is scope for further work in the application of integrated digital hierarchical control and protection systems to power systems. Before an adaptive hierarchical distance relaying scheme can be implemented further work needs to be undertaken in at least two areas:

(i) **Relay Update Frequency / Response to Change:** In an adaptive relay, the functionality of the device is updated to reflect current power system conditions. However, to ensure the integrity of the protection system, it remains to be established how often the relays require updating to give the required performance.

(ii) **Failure:** Should any part of the integrated digital hierarchical control and protection system fail, in particular the communications systems, it remains to be established how the relays would operate and what their performance would be.

The improvement of operational intertripping is another obvious area for exploitation by integrated digital hierarchical control and protection systems. Actual work in this area was however, outside the terms of reference of the research.

CHAPTER 11

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APPENDIX A

NORTH WALES POWER SYSTEM OPERATING CONDITIONS AND DATA

This appendix details the power system data and operating conditions for the North Wales System depicted in Fig.5.1. The parameters for the system are presented in Tables A.1.1 to A.1.4 for busbars, transmission lines, transformers and generators respectively. It should be noted that additional equivalent generators have been included in Table A.1.4 to incorporate the effects of the rest of the grid. The power system operating conditions correspond to the 1994 / 95 winter peak data. Busbar, transmission line and transformer load flow data are presented in Tables A.2.1 to A.2.3. Using this information it is possible to derive the faulted network conditions, adaptively set the relays, and analyse the performance. The volume of this additional data prohibits incorporation in this documentis. However, it is available in reference [A.1].

Appendix A: North Wales Power System Operating Conditions and Data

Table A.1.1: Busbar Data	
No.	Name
1	CAP-01
2	CAP-02
3	CAP-03
4	CAP-06
5	CAP-07
6	CAP-08
7	DEE-01
8	DEE-02
9	DIN-01
10	FFE-01
11	FRO-02
12	LEG-02
13	PEN-01
14	PEN-02
15	TRA-01
16	TRA-02
17	TRA-03
18	WYL-01
19	WYL-02
20	BIR-01

Table A.1.1: Busbar Data cont...	
No.	Name
21	CAP-04
22	CAP-05
23	DAI-01
24	DIN-02
25	DIN-03
26	DIN-04
27	DIN-05
28	DIN-06
29	DIN-07
30	FFE-02
31	FFE-03
32	FRO-01
33	TRA-04
34	TRA-05
35	TRA-06
36	TRA-07
37	WYL-03
38	WYL-04
39	WYL-05
40	WYL-06
41	LEG-01

Table A.1.2: Transmission Line Data					
No.	Send Bus	Receive Bus	Resistance (pu)	Reactance (pu)	Susceptance (pu)
1	LEG-01	DEE-01	0.00052	0.00508	0.15822
2	LEG-01	TRA-01	0.00183	0.01464	0.44702
3	DEE-01	PEN-01	0.00095	0.01342	0.53661
4	DEE-01	PEN-01	0.00095	0.01342	0.53661
5	DEE-01	CAP-01	0.00014	0.00196	0.07840
6	DEE-01	CAP-02	0.00014	0.00196	0.07844
7	DEE-01	TRA-01	0.00189	0.01493	0.46292
8	DEE-01	DAI-01	0.00145	0.01147	0.35550
9	DEE-01	DAI-01	0.00145	0.01146	0.35529
10	PEN-01	TRA-01	0.00104	0.00867	1.40000
11	PEN-01	DIN-01	0.00007	0.00108	2.51500
12	PEN-01	DIN-01	0.00010	0.00139	1.47780
13	PEN-01	WYL-01	0.00042	0.00599	0.23946
14	PEN-01	WYL-01	0.00042	0.00599	0.23946
15	TRA-02	FFE-01	0.00086	0.00296	0.03014
16	TRA-02	FFE-01	0.00086	0.00296	0.02080
17	BIR-01	CAP-03	0.00077	0.00652	0.04128
18	FRO-01	CAP-06	0.00046	0.00647	0.05935

Table A.1.3: Transformer Line Data					
No.	Send Bus	Receive Bus	Resistance (pu)	Reactance (pu)	Susceptance (pu)
1	LEG-01	LEG-02	0.00000	0.01919	0.00000
2	DEE-01	DEE-02	0.00000	0.08183	0.00000
3	DEE-01	DEE-02	0.00000	0.08183	0.00000
4	PEN-01	PEN-02	0.00000	0.08292	0.00000
5	PEN-01	PEN-02	0.00000	0.08321	0.00000
6	TRA-01	TRA-02	0.00000	0.01665	0.00000
7	TRA-01	TRA-02	0.00000	0.01547	0.00000
8	TRA-02	TRA-03	0.00000	0.12408	0.00000
9	TRA-02	TRA-03	0.00000	0.12250	0.00000
10	TRA-02	TRA-04	0.00000	0.09712	0.00000
11	TRA-02	TRA-05	0.00000	0.09837	0.00000
12	TRA-02	TRA-06	0.00000	0.09739	0.00000
13	TRA-02	TRA-07	0.00000	0.09647	0.00000
14	FFE-01	FFE-02	0.00000	0.09811	0.00000
15	FFE-01	FFE-03	0.00000	0.09700	0.00000
16	DIN-01	DIN-02	0.00000	0.05156	0.00000
17	DIN-01	DIN-03	0.00000	0.05123	0.00000
18	DIN-01	DIN-04	0.00000	0.05123	0.00000
19	DIN-01	DIN-05	0.00000	0.05123	0.00000
20	DIN-01	DIN-06	0.00000	0.05156	0.00000

Table A.1.3: Transformer Line Data cont...					
No.	Send Bus	Receive Bus	Resistance (pu)	Reactance (pu)	Susceptance (pu)
21	DIN-01	DIN-07	0.00000	0.05156	0.00000
22	WYL-01	WYL-03	0.00000	0.04795	0.00000
23	WYL-01	WYL-04	0.00000	0.02763	0.00000
24	WYL-01	WYL-05	0.00000	0.04751	0.00000
25	WYL-01	WYL-06	0.00000	0.02763	0.00000
26	WYL-01	WYL-02	0.00000	0.08591	0.00000
27	WYL-01	WYL-02	0.00000	0.08636	0.00000
28	WYL-01	WYL-02	0.00000	0.09077	0.00000
29	CAP-01	CAP-03	0.00000	0.01600	0.00000
30	CAP-01	CAP-04	0.00000	0.01684	0.08000
31	CAP-02	CAP-06	0.00000	0.01682	0.00000
32	CAP-04	CAP-07	0.00000	0.08522	0.00000
33	CAP-04	CAP-08	0.00000	0.08333	0.00000
34	CAP-05	CAP-07	0.00000	0.08333	0.00000
35	CAP-05	CAP-08	0.00000	0.08355	0.00000
36	CAP-05	CAP-08	0.00000	0.08478	0.00000
37	FRO-01	FRO-02	0.00000	0.12833	0.00000
38	FRO-01	FRO-02	0.00000	0.12767	0.00000
39	FRO-01	FRO-02	0.00000	0.08438	0.00000
40	FRO-01	FRO-02	0.00000	0.08438	0.00000
41	CAP-02	CAP-05	0.00019	0.01597	0.00000

Table A.1.4: Generator Data			
No.	Busbar	Resistance (pu)	Reactance (pu)
1	BIR-01	0.00000	0.01732
2	CAP-04	0.00000	0.01154
3	CAP-05	0.00000	0.01154
4	DAI-01	0.00000	0.00787
5	DIN-02	0.00000	0.06545
6	DIN-03	0.00000	0.06545
7	DIN-04	0.00000	0.06545
8	DIN-05	0.00000	0.06545
9	DIN-06	0.00000	0.06545
10	DIN-07	0.00000	0.06545
11	FFE-02	0.00000	0.16011
12	FFE-03	0.00000	0.16011
13	FRO-01	0.00000	0.01732
14	TRA-04	0.00000	0.17937
15	TRA-05	0.00000	0.17937
16	TRA-06	0.00000	0.17995
17	TRA-07	0.00000	0.16483
18	WYL-03	0.00000	0.09228
19	WYL-04	0.00000	0.09429
20	WYL-05	0.00000	0.09129
21	WYL-06	0.00000	0.09033
22	LEG-01	0.00000	0.00962

Appendix A: North Wales Power System Operating Conditions and Data

Table A.2.1: Busbar Load Flow Data

No.	Name	Voltage Mag. (pu)	Voltage Ang. (°)	ActivePower (MW)	ReactivePower (MVAr)
1	CAP-01	1.00958	3.17329	0.0000	0.0000
2	CAP-02	1.01045	3.46748	0.0000	0.0000
3	CAP-03	1.01038	3.60525	0.0000	0.0000
4	CAP-06	1.00688	4.76539	0.0000	0.0000
5	CAP-07	.98496	-.64054	108.5000	22.6350
6	CAP-08	.98539	-.51949	108.5000	22.8779
7	DEE-01	1.00916	2.94338	0.0000	0.0000
8	DEE-02	.99746	-2.38993	228.6588	17.8877
9	DIN-01	1.02936	6.60513	0.0000	0.0000
10	FFE-01	1.01691	5.65566	0.0000	0.0000
11	FRO-02	1.00608	5.27272	0.0000	0.0000
12	LEG-02	.98665	-3.46812	311.0000	59.2415
13	PEN-01	1.02864	6.29256	0.0000	60.0001
14	PEN-02	1.02369	3.41991	127.0558	9.0137
15	TRA-01	1.01909	4.27055	0.0000	0.0000
16	TRA-02	1.01631	5.43239	0.0000	0.0000
17	TRA-03	1.01631	5.43239	0.0000	0.0000
18	WYL-01	1.02934	7.15359	0.0000	0.0000
19	WYL-02	1.02375	1.91398	329.4420	4.5129
20	BIR-01	1.01095	3.77968	-48.0775	-1.1556

Table A.2.1: Busbar Load Flow Data cont...					
No.	Name	Voltage Mag. (pu)	Voltage Ang. (^{o})	ActivePower (MW)	ReactivePower (MVAr)
21	CAP-04	1.00892	4.69867	-378.0001	-61.0000
22	CAP-05	1.02096	6.49081	-341.5375	-72.0851
23	DAI-01	.990511	.37635	508.6049	286.2596
24	DIN-02	1.01731	13.35196	-238.5864	9.7273
25	DIN-03	1.01734	13.30837	-238.5864	9.9091
26	DIN-04	1.01734	13.30837	-238.5864	9.9091
27	DIN-05	1.01734	13.30837	-238.5864	9.9091
28	DIN-06	1.02936	6.60513	0.0000	0.0000
29	DIN-07	1.02936	6.60513	0.0000	0.0000
30	FFE-02	1.00711	12.86977	-131.0768	1.8111
31	FFE-03	1.00713	12.78757	-131.0768	1.9992
32	FRO-01	1.00608	5.27272	-137.0876	24.5947
33	TRA-04	1.01631	5.43239	0.0000	0.0000
34	TRA-05	1.01631	5.43239	0.0000	0.0000
35	TRA-06	1.01631	5.43239	0.0000	0.0000
36	TRA-07	1.01631	5.43239	0.0000	0.0000
37	WYL-03	1.03420	12.71137	-215.0000	-20.9186
38	WYL-04	1.03096	10.36284	-215.0000	-12.0538
39	WYL-05	1.03411	12.66068	-215.0000	-20.7265
40	WYL-06	1.03096	10.36284	-215.0000	-12.0538
41	LEG-01	1.00000	0.000000	1238.0000	45.9996

Table A.2.2: Transmission Line Load Flow Data

No.	Send Bus	Receive Bus	Send P (MW)	Send Q (MVAr)	Receive P (MW)	Receive Q (MVAr)
1	LEG-01	DEE-01	-1025.034	-57.143	1030.510	94.673
2	LEG-01	TRA-01	-524.020	-67.941	529.084	62.883
3	DEE-01	PEN-01	-459.001	-128.117	461.061	101.505
4	DEE-01	PEN-01	-459.001	-128.117	461.061	101.505
5	DEE-01	CAP-01	-209.000	-10.009	209.060	2.863
6	DEE-01	CAP-02	-478.000	-34.010	478.315	30.426
7	DEE-01	TRA-01	-165.149	-67.943	165.691	24.619
8	DEE-01	DAI-01	255.374	116.953	-254.186	-143.095
9	DEE-01	DAI-01	255.608	117.051	-254.418	-143.165
10	PEN-01	TRA-01	434.816	-5.388	-432.912	-125.500
11	PEN-01	DIN-01	-536.883	-165.011	537.075	-98.336
12	PEN-01	DIN-01	-417.110	-100.040	417.275	-54.144
13	PEN-01	WYL-01	-265.002	-4.006	265.281	-17.368
14	PEN-01	WYL-01	-265.002	-4.006	265.281	-17.368
15	TRA-02	FFE-01	-130.932	16.055	131.077	-18.670
16	TRA-02	FFE-01	-130.932	16.537	131.077	-18.187
17	BIR-01	CAP-03	48.077	1.156	-48.060	-5.224
18	FRO-01	CAP-06	137.088	-24.594	-137.000	19.813

Table A.2.3: Transformer Load Flow Data

No.	Send Bus	Receive Bus	Send P (MW)	Send Q (MVAr)	Receive P (MW)	Receive Q (MVAr)
1	LEG-01	LEG-02	311.000	79.000	-311.000	-59.242
2	DEE-01	DEE-02	114.329	19.760	-114.329	-8.944
3	DEE-01	DEE-02	114.329	19.760	-114.329	-8.944
4	PEN-01	PEN-02	63.639	7.736	-63.639	-4.515
5	PEN-01	PEN-02	63.417	7.709	-63.417	-4.499
6	TRA-01	TRA-02	-126.122	18.301	126.122	-15.697
7	TRA-01	TRA-02	-135.742	19.697	135.742	-16.895
8	TRA-02	TRA-03	0.000	0.000	0.000	0.000
9	TRA-02	TRA-03	0.000	0.000	0.000	0.000
10	TRA-02	TRA-04	0.000	0.000	0.000	0.000
11	TRA-02	TRA-05	0.000	0.000	0.000	0.000
12	TRA-02	TRA-06	0.000	0.000	0.000	0.000
13	TRA-02	TRA-07	0.000	0.000	0.000	0.000
14	FFE-01	FFE-02	-131.077	18.428	131.077	-1.805
15	FFE-01	FFE-03	-131.077	18.428	131.077	-1.994
16	DIN-01	DIN-02	-238.588	38.120	238.588	-9.713
17	DIN-01	DIN-03	-238.588	38.120	238.588	-9.895
18	DIN-01	DIN-04	-238.588	38.120	238.588	-9.895
19	DIN-01	DIN-05	-238.588	38.120	238.588	-9.895
20	DIN-01	DIN-06	0.000	0.000	0.000	0.000

Table A.2.3: Transformer Load Flow Data cont...						
No.	Send Bus	Receive Bus	Send P (MW)	Send Q (MVAr)	Receive P (MW)	Receive Q (MVAr)
21	DIN-01	DIN-07	0.000	0.000	0.000	0.000
22	WYL-01	WYL-03	-215.001	-0.010	215.001	20.929
23	WYL-01	WYL-04	-215.000	-0.005	215.000	12.060
24	WYL-01	WYL-05	-215.001	-0.009	215.001	20.737
25	WYL-01	WYL-06	-215.000	-0.005	215.000	12.060
26	WYL-01	WYL-02	112.007	11.820	-112.007	-1.535
27	WYL-01	WYL-02	111.424	11.759	-111.424	-1.527
28	WYL-01	WYL-02	106.010	11.187	-106.010	-1.452
29	CAP-01	CAP-03	-48.060	-4.858	48.060	5.224
30	CAP-01	CAP-04	-161.000	1.994	161.000	-5.854
31	CAP-02	CAP-06	-137.000	22.992	137.000	-19.813
32	CAP-04	CAP-07	108.500	33.426	-108.500	-22.635
33	CAP-04	CAP-08	108.500	33.430	-108.500	-22.878
34	CAP-05	CAP-07	0.000	0.000	0.000	0.000
35	CAP-05	CAP-08	0.000	0.000	0.000	0.000
36	CAP-05	CAP-08	0.000	0.000	0.000	0.000
37	FRO-01	FRO-02	0.000	0.000	0.000	0.000
38	FRO-01	FRO-02	0.000	0.000	0.000	0.000
39	FRO-01	FRO-02	0.000	0.000	0.000	0.000
40	FRO-01	FRO-02	0.000	0.000	0.000	0.000
41	CAP-02	CAP-05	-341.315	-53.419	341.537	72.086

APPENDIX B

THE INFLUENCE OF NETWORK CONDITIONS ON THE MEASURED IMPEDANCE BY DISTANCE RELAYS FOR SINGLE PHASE TO EARTH FAULTS

Consider the power system network of Fig.6.1. The impedances either side of the fault point may be expressed, in sequence form, as:

$$Z_{M1} = Z_{sm1} + \alpha.Z_{l1} \tag{B.1}$$

$$Z_{M0} = Z_{sm0} + \alpha.Z_{l0} \tag{B.2}$$

$$Z_{N1} = Z_{sn1} + (1-\alpha).Z_{l1} \tag{B.3}$$

$$Z_{N0} = Z_{sn0} + (1-\alpha).Z_{l0} \tag{B.4}$$

Prior to the fault, the pre-fault a-phase load current flowing in the network, I_{LD1}, is given by:

$$I_{LD1} = \frac{E_{m1} - E_{n1}}{Z_{M1} + Z_{N1}} \tag{B.5}$$

and the pre-fault voltage at the fault point is given by:

$$U_{f1} = E_{m1} - I_{LD1}.Z_{M1} \tag{B.6}$$

The total impedance looking into the network at the fault point is given by:

$$Z_{\Sigma} = \frac{2.Z_{M1}.Z_{N1}}{Z_{M1} + Z_{N1}} + \frac{Z_{M0}.Z_{N0}}{Z_{M0} + Z_{N0}} \tag{B.7}$$

When a fault occurs on the system with resistance R_f the sequence fault currents are given by:

$$I_{f1} = I_{f2} = I_{f0} = \frac{U_{f1}}{Z_{\Sigma}+3.R_f} \tag{B.8}$$

The total fault current is given by:

$$I_{af} = I_{f1} + I_{f2} + I_{f0} = \frac{3.U_{af1}}{Z_{\Sigma}+3.R_f} \tag{B.9}$$

The sequence currents from M to F are dependent on the sequence component distribution factors. Thus:

$$I_{M1} = I_{M2} = c_1.I_{f1} = \frac{c_1.U_{f1}}{Z_{\sum}+3.R_f} \tag{B.10}$$

and

$$I_{M0} = c_0.I_{f0} = \frac{c_0.U_{f1}}{Z_{\sum}+3.R_f} \tag{B.11}$$

where:

$$c_1 = \frac{Z_{N1}}{Z_{M1} + Z_{N1}} \tag{B.12}$$

$$c_0 = \frac{Z_{N0}}{Z_{M0} + Z_{N0}} \tag{B.13}$$

Thus, the a-phase current flowing in the faulted network is given by:

$$I_M = I_{LD1} + I_f = I_{LD1}+I_{M1} + I_{M2} + I_{M0} \tag{B.14}$$

Now:

Appendix B: The Influence of Network Conditions on the Measured Impedance by Distance Relays for Single Phase to Earth Faults

$$Z_{measured} = \alpha.Z_{l1} + \frac{3.R_f I_f}{I_a + K_{res}.I_{res}} \tag{B.15}$$

Substitution of equations (B.6) and (B.14) into equation (B.15) yields:

$$Z_{measured} = \alpha.Z_{l1} + \frac{\dfrac{3.R_f U_{f1}}{Z_{\sum} + 3.R_f}}{I_{LD1} + I_{M1} + I_{M2} + I_{M0} + K_{res}.I_{res}} \tag{B.16}$$

Simplifying:

$$Z_{measured} = \alpha.Z_{l1} + \frac{3.R_f}{\dfrac{Z_{\sum} + 3.R_f}{U_{f1}}.[I_{LD1} + I_{M1} + I_{M2} + I_{M0} + K_{res}.I_{res}]} \tag{B.17}$$

Substitution of equations (B.10) and (B.11) into equation (B.17) and simplifying gives:

$$Z_{measured} = \alpha.Z_{l1} + \frac{3.R_f}{\dfrac{Z_{\sum} + 3.R_f}{U_{f1}}.I_{LD1} + 2.c_1 + c_0.(1 + 3.K_{res})} \tag{B.18}$$

Substitution of equation (B.6) into equation (B.18) gives:

Appendix B: The Influence of Network Conditions on the Measured Impedance by Distance Relays for Single Phase to Earth Faults

$$Z_{measured} = \alpha.Z_{l1} + \frac{3.R_f}{\frac{[Z_{\Sigma} + 3.R_f].I_{LD1}}{E_{m1} - I_{LD1}.Z_{M1}} + 2.c_1 + c_0.[1 + 3.K_{res}]} \qquad \textbf{(B.19)}$$

Eliminating I_{LD1} from equation (B.19) by substitution of equation (B.5) and simplifying yields:

$$Z_{measured} = \alpha.Z_{l1} + \frac{3.R_f}{\frac{[Z_{\Sigma} + 3.R_f].[E_{m1} - E_{n1}]}{E_{m1}.Z_{N1} + E_{n1}.Z_{M1}} + 2.c_1 + c_0.[1 + 3.K_{res}]} \qquad \textbf{(B.20)}$$

APPENDIX C

TRANSMISSION LINE PARAMETERS

Table C.1: Parameters for a 100 km, 400 kV Transmission Line

Parameter	Quantity
Positive Phase Sequence Resistance (Ω / km)	0.0175
Positive Phase Sequence Reactance (Ω / km)	0.31
Zero Phase Sequence Resistance (Ω / km)	0.1060
Zero Phase Sequence Reactance(Ω / km)	0.88
Line Length (km)	100.0
Nominal Voltage (kV)	400.0

APPENDIX D

POWER SYSTEM PARAMETERS FOR ILLUSTRATING THE INFLUENCE OF OPERATING CONDITIONS ON MEASURED IMPEDANCE

The table below highlights the operating conditions used for demonstrating the influence of different parameters on the measured impedance. In each case, where a parameter is varied, the associated parameter in the table should be ignored.

Table D.1: Power System Parameters

Parameter	Quantity
Capacity of Source M (GVA):	20.0
X to R Ratio of Source M:	30.0
Z_{sm0} to Z_{sm1} Ratio of Source M:	1.5
Real Voltage of Source M (kV):	400.0
Reactive Voltage of Source M (kV):	0.0
Capacity of Source N (GVA):	20.0
X to R Ratio of Source N:	30.0
Z_{sm0} to Z_{sm1} Ratio of Source N:	1.5
Real Voltage of Source N (kV):	400.0
Reactive Voltage of Source N (kV):	0.0
Fault Resistance Range (Ω):	0.0 - 300.0

APPENDIX E

POWER SYSTEM PARAMETERS WITH CONDITIONS OF PRE-FAULT IMPORTING LOAD AT RELAYING POINT

Table E.1: Power System Parameters with Load Flowing from N to M	
Parameter	Quantity
Capacity of Source M (GVA):	20.0
X to R Ratio of Source M:	30.0
Z_{sm0} to Z_{sm1} Ratio of Source M:	1.5
Real Voltage of Source M (kV):	410.0
Reactive Voltage of Source M (kV):	-90.0
Capacity of Source N (GVA):	20.0
X to R Ratio of Source N:	30.0
Z_{sm0} to Z_{sm1} Ratio of Source N:	1.5
Real Voltage of Source N (kV):	400.0
Reactive Voltage of Source N (kV):	0.0
Fault Resistance Range (Ω):	0.0 - 55.0

APPENDIX F

POWER SYSTEM PARAMETERS WITH CONDITIONS OF PRE-FAULT EXPORTING LOAD AT RELAYING POINT

Table F.1: Power System Parameters with Load Flowing from M to N

Parameter	Quantity
Capacity of Source M (GVA):	20.0
X to R Ratio of Source M:	30.0
Z_{sm0} to Z_{sm1} Ratio of Source M:	1.5
Real Voltage of Source M (kV):	400.0
Reactive Voltage of Source M (kV):	0.0
Capacity of Source N (GVA):	20.0
X to R Ratio of Source N:	30.0
Z_{sm0} to Z_{sm1} Ratio of Source N:	1.5
Real Voltage of Source N (kV):	410.0
Reactive Voltage of Source N (kV):	-90.0
Fault Resistance Range (Ω):	0.0 - 100.0